



Suruhanjaya Tenaga
Energy Commission

Guidelines

On Tariff Determination Under Incentive
Based Regulation For Sabah Electricity
Sdn. Bhd

[Electricity Supply Act 1990 (Act 447)]

ELECTRICITY SUPPLY ACT 1990

[Act 447]

GUIDELINES ON TARIFF DETERMINATION UNDER INCENTIVE BASED REGULATION FOR SABAH ELECTRICITY SDN. BHD.

GP/ST/ No. 3/2016

IN exercise of the power conferred by Sections 26 and 50C of the Electricity Supply Act 1990 [Act 447], the Commission makes the following Guidelines:

Citation and Commencement

1. These Guidelines may be cited as the Guidelines on Tariff Determination Under Incentive Based Regulation for Sabah Electricity Sdn. Bhd.
2. These Guidelines shall come into operation on the date of its registration.

Purpose and Application of the Guidelines

3. These Guidelines describes the methodology, principles, procedures and requirements that shall be complied by Sabah Electricity Sdn. Bhd. in the submission of the electricity tariff proposal or revision as required under Section 26 of the Electricity Supply Act 1990.

The Tariff Determination Framework

4. The framework for tariff determination shall be based on eleven (11) Regulatory Implementation Guidelines (“RIG”) as follow:
 - i) RIG 1, which defines the business entities of SESB, as in **ANNEX A**
 - ii) RIG 2, which defines the tariff setting framework, as in **ANNEX B**;
 - iii) RIG 3, which sets the revenue requirement principles, as in **ANNEX C**;
 - iv) RIG 4, which sets the Weighted Average Cost of Capital of SESB, as in **ANNEX D**;

- v) RIG 5, which establishes the operating cost, capital cost, asset and consumption templates, as in **ANNEX E**;
- vi) RIG 6, which establishes the incentive framework for operational performance, as in **ANNEX F**;
- vii) RIG 7, which defines the cost allocation principles, as in **ANNEX G**;
- viii) RIG 8, which establishes the imbalance cost pass through mechanism, as in **ANNEX H**;
- ix) RIG 9, which defines the tariff design principles, as in **ANNEX I**;
- x) RIG 10, which establishes the regulatory accounts process, as in **ANNEX J**; and
- xi) RIG 11, which establishes the process for determining the revenue requirement and tariff, as in **ANNEX K**.

Notice by the Commission

- 5. The Commission may issue written notices from time to time in relation to these Guidelines.

Amendment and Variation

- 6. The Commission may at any time review, amend, modify, vary or revoke these Guidelines.

Dated: 04 May 2016



DATUK IR. AHMAD FAUZI BIN HASAN
Chief Executive Officer
for Energy Commission

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ANNEX A

REGULATORY IMPLEMENTATION GUIDELINE 1

- RIG 1 -

Defines business entities; specify functions of each business entity; specify the flow of funds between business entities.



1. Objective

The objectives of RIG 1 are as follows:

- Establish the business entities of Sabah Electricity Sdn Bhd (SESB) which will be subject to incentive-based regulation (IBR);
- Define the functions of each of the business activity; and
- Specify the flow of funds between the business activities.

2. Business Entities of SESB

There are two broad choices for establishing the business entities of SESB, the Simple Model and the Market Managed Model.

2.1 Simple Model

In the Simple Model, SESB's business is categorised into three business entities, which are Generation, Transmission and Customer Services. These three business entities are defined below

- **Generation:** This business entity includes the management and operation of grid and non-grid generation plants owned by SESB (SESB generation), the procurement of generation supply from various Independent Power Producers (IPPs). The objective of Generation is to ensure that there is sufficient generation supply to meet the demand requirement of electricity customers.
- **Transmission:** This business entity includes the management, maintenance and development of the SESB transmission system and system operations for the transmission of electricity to end customers.
- **Customer Services:** This business entity includes the management, maintenance and development of the distribution system and the sale of electricity to customers.

The Customer Services business entity charges electricity customers a tariff for the use of electricity. This tariff is a bundled tariff and incorporates a charge for Generation, Transmission and Customer Services. Customer Services receives all the tariff revenue from electricity customers and subsequently used to cover the cost incurred by the Transmission business entity as its share of revenue based on Transmission Tariffs and Generation business entity as its share of the revenue based on Generation Tariffs.

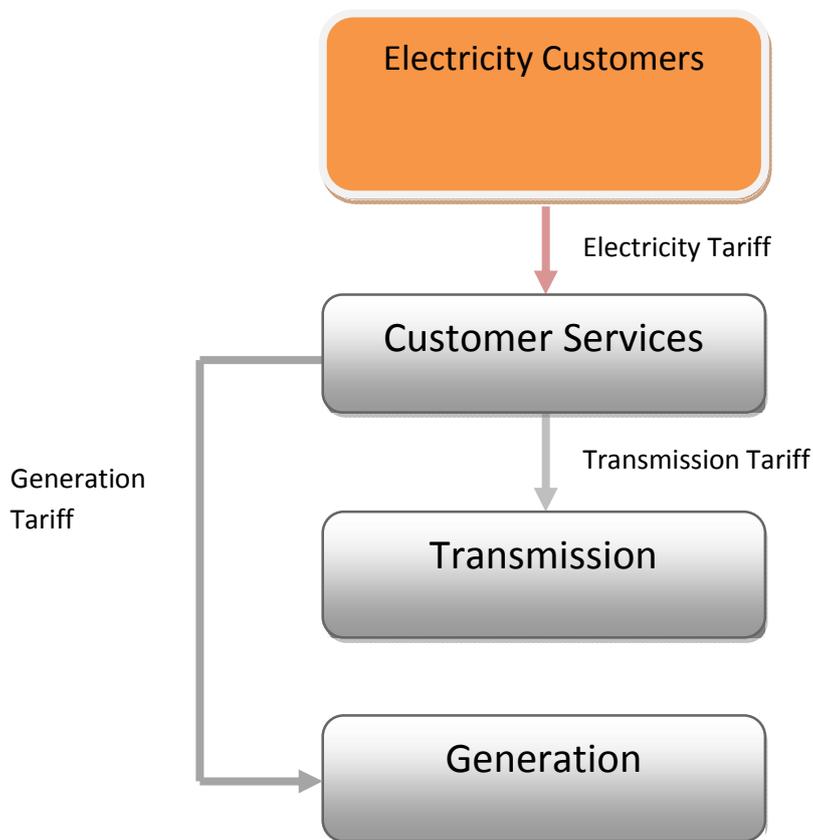
RIG 1

Define Business Entity

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The flow of funds between the three business entities is shown below.

FIG: Flow of funds for Simple Model



The three business entities of Generation, Transmission and Customer Services will be ring fenced with separate accounts.

2.2 Managed Market Model

In the Managed Market Model, SESB's business is categorised into five business entities, which are SESB Generation which include grid and non-grid plants, Single Buyer, Transmission, System Operator and Customer Services. These business entities are defined below:

- Single Buyer: The main function of the Single Buyer is to procure electricity from IPPs and SESB Generation based on the terms of the Power Purchase Agreements (PPAs) entered into between SESB and the IPPs and Service Level Agreements (SLAs) entered into between SESB Planning Division and SESB Generation. The Single Buyer shall develop dispatch schedules based on least cost scheduling methodology for

SESB's generation and the IPPs plants. The least cost scheduling methodology is based on the fuel costs (heat rate and fuel price) and variable operating costs of all the generation plants available for all IPPs and SESB generation plants. The Single Buyer produces the day-ahead scheduling.

- SESB Generation: This business entity includes the ownership, management and operation of grid and non-grid generation plants owned by SESB. Single Buyer procures from SESB Generation for the sale of electricity based on SLAs for the following plants:
 - Patau-Patau Power Station;
 - Tenom Pangi Hydro Power Station;
 - Kubota Power Station; and
 - Additional plants (if necessary).

On SESB grid and non-grid plants which are recognised and identified as Non-SLAs plants, shall be dispatched based on the estimated heat rate, variable operating rate (VOR), capacity charge and fixed operating rate (FOR) to recover its respective operating costs and book value for the remaining life of the plant.

- Transmission: This business entity includes the management, maintenance and development of the SESB transmission system for the transmission of electricity to end customers. Transmission system planning is done by the Transmission Planning, Planning Division for the usage of Transmission business entity.
- System Operator: This business entity includes the current functions of transmission system operations of SESB.
- Customer Services: This business entity includes the management, maintenance and development of the distribution system Non-SLAs and the sale of electricity to customers.

In addition to the five Business entities of SESB, the IPPs are collectively the sixth business entity, contracting with the Single Buyer for sale of electricity.

The Customer Services business entity charges electricity customers a tariff for the use of electricity. This tariff is a bundled tariff and incorporates a charge for all Generation (IPPs, SESB generation and cost of Single Buyer), Transmission, System Operations and Customer Services. Customer Services receives all the tariff revenue from electricity customers and

RIG 1

Define Business Entity

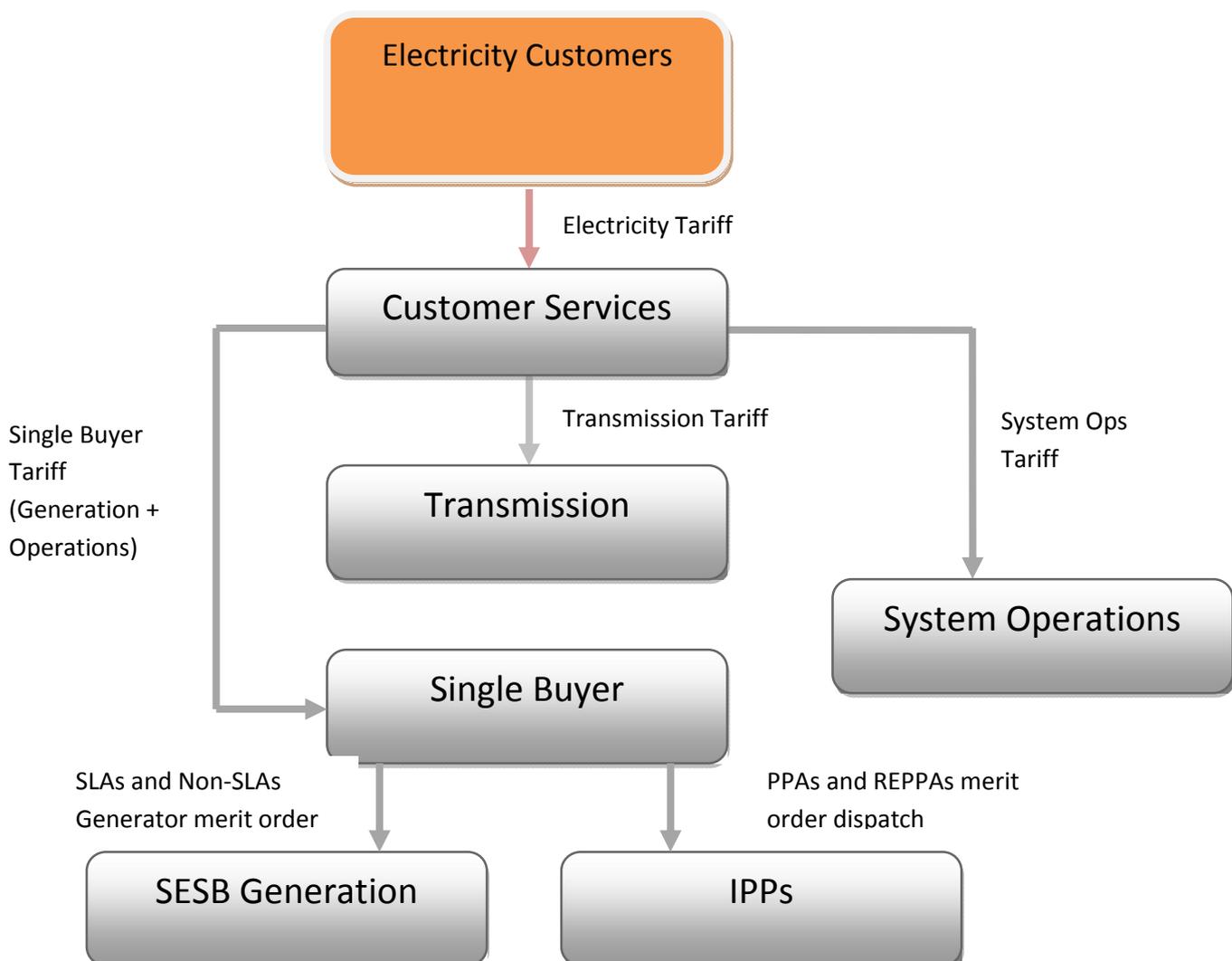
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subsequently used to cover the cost of Transmission and the System Operations business entity as its share of revenue based on Transmission Tariffs and tariff for System Operations.

The Single Buyer charges a Single Buyer Tariff to the Customer Services business entity, comprising a **Generation component** (based on forecasts costs of generation determined by the capacity payment and FOR in the PPAs, SLAs, Non-SLAs, Renewable Energy Power Purchase Agreements - REPPAs, and all variable generation costs based on the merit order dispatch) and an **Operations component** (based on the operating costs of managing the operations of the Single Buyer). The Single Buyer receives the Generation Revenue and pays SESB Generation and the IPPs.

The flow of funds between the five SESB business entities and the IPP's is shown below.

FIG: Flow of funds for Managed Market Model



The five business entities of SESB Generation, Single Buyer, Transmission, System Operations and Customer Service will be ring fenced with separate accounts.

3. Recommendation

The Suruhanjaya Tenaga's (ST) preference is to adopt the Managed Market Model. This is because;

- the Managed Market Model is consistent with SESB's operations;
- enhances transparency between SESB generation and IPPs; and
- is broadly consistent with the recommendations of the Incentive-Based Regulation (IBR) in the Peninsular of Malaysia.

The Managed Market Model requires the operating rules for the Single Buyer to be established upfront. The principles for the Single Buyer and the high level rules for dispatch are incorporated in the current Sabah and Labuan Grid Code. However, further work needs to be done to develop in detail the operating procedures (or the Managed Market Rules) to ensure transparency and clear guidelines for the Single Buyer to follow in preparing the day-ahead dispatch schedule. The rules for producing the day-ahead dispatch schedule should be comprehensive with clear guidelines established upfront which articulate how the Single Buyer will respond to upset conditions, such as fuel curtailment or the need to re-optimize dispatch based on fuel supply (or fuel contract) issues.

The separation of the Single Buyer and System Operations will maintain a proper check and balance with the Single Buyer focusing on developing the rules for this Managed Market Model and taking on a more strategic role and ensuring transparency, and System Operations focusing on real time operations ensuring system security and stability on a real time basis. The Single Buyer currently has the relevant knowledge on fuel security and availability and expertise on the contractual terms of the PPAs and the SLAs to enable it to take a more strategic view of dispatch.

The Single Buyer and the System Operators could also be merged into a single business entity responsible for both real time system dispatch and security and producing the day-ahead dispatch based on the managed market rules. However our preference is to initially have separation of duties between System Operations and Single Buyer to ensure that both entities are focused on their respective roles. Once the rules of this managed market are well established, System Operations and the Single Buyer can be merged if required.

Finally, the recommended model will require some adjustments to SESB's divisional accounting framework, as the costs (and business activities) of the Single Buyer and System Operations will need to be separately identified and ring fenced from other parts of the business.

ANNEX B

REGULATORY IMPLEMENTATION GUIDELINE 2

- RIG 2 -

Defines the tariff setting framework for each business entity (price or revenue regulation, regulatory term)



1. Objective

The objectives of RIG 2 are as follows:

- Establish the tariff setting framework for each SESB business entity operating in the Managed Market Model includes setting the benchmark for Government subsidies (if necessary); and
- Set the Regulatory Term for each of the five SESB business entities.

2. Tariff Setting Framework

There are three choices for setting the tariffs which the five SESB business entities can choose from. These choices are outlined below:

2.1 Price Cap

Under a pure Price Cap regulatory framework, price (and price path) is set for the Regulatory Term based on forecasts of cost and electricity sales. The calculation of price and price path under a Price Cap regime is outlined in Regulatory Guideline Number 3 (RIG 3).

Business entities operating under a Price Cap regime are exposed to all revenue risk based on actual electricity sales varying from forecasts of electricity sales used to set price and price path under RIG 3. That is, the revenue for business entities will be based on actual electricity sales, which may be different to projected revenue based on initial forecasts electricity sales used to set price as per RIG 3. This is because prices are not adjusted within a Regulatory Term for actual electricity sales outcome.

2.2 Revenue Cap

Under a pure Revenue Cap regulatory framework, annual revenue is set for every year of the Regulatory Term. The calculation of annual revenues under a Revenue Cap regime is outlined in RIG 3.

Business entities operating under a Revenue Cap regime are not exposed to any revenue risk. This is because if actual revenue is different to forecast revenue due to differences between actual and forecast electricity sales, prices are adjusted to make up for the revenue difference.

2.3 Actual cost

Under an Actual Cost recovery model, the regulated entity is allowed to recover all of its actual costs. Prices adjust to reflect changes in costs to ensure that the regulated entity

does not earn less (or more) than the cost of providing services. Typically, operators of companies managing the wholesale market operate under an Actual Cost recovery regime.

2.4 Hybrid Model

The Hybrid Model is a combination of a Price Cap and a Revenue Cap regime or alternatively a combination of all three regimes as discussed previously (Price Cap, Revenue Cap and Actual Cost). The Hybrid Model offers the flexibility to apply either a Price Cap or Revenue Cap or Actual Cost to different parts of the regulated value chain. For example, a regulated vertically integrated electricity utility may choose to apply a Price Cap where costs vary with electricity sales and Revenue Cap where costs of service are largely fixed and do not vary in the short term with electricity sales.

3. Analysis of the options and recommendation on Tariff Setting Framework

Typically, regulated distribution businesses operate under a Price Cap regime, with transmission businesses operating under a Revenue Cap regime. This is because transmission costs are largely fixed and do not vary with electricity sales in the short to medium term. However, distribution businesses' costs vary more with electricity sales due to customer connections and localised capacity expansions to meet electricity demand growth.

Generation costs comprise largely of plant costs and fuel. In competitive markets, the recovery of generation costs depends upon the nature of the market. Under a market pool, recovery of generation costs depends primarily upon pool price, bidding strategy of market participants and the contracting strategy of the generator. Under a regulated model, like that of Singapore for domestic customers, generators work under a pure Price Cap regime. In Australia, initially when the domestic market was regulated generators operated under vesting contracts which was a pure Price Cap regime.

The ST's recommendation is the following:

3.1 Bundled tariff for final electricity customers

It is expected that Customer Services will initially charge a bundled tariff to electricity customers. This bundled tariff will be the sum of a tariff component applicable for Customer Services plus tariff components for Transmission, System Operations and Single Buyer Costs (including a generation specific tariff and other operating cost specific tariff).

The separate identification of costs and revenues for each SESB business entity as specified in RIG 1 under the managed market model will enable disaggregation or unbundling of tariff components for final customers should this be required at a later date.

3.2 Customer Services

It is intended that a pure Price Cap regime will apply to Customer Services. The Customer Services component of the bundled tariff will be fixed for the Regulatory Term, and will not vary with changes in electricity sales within the Regulatory Term.

The price which Customer Services charges customers will be determined in accordance with RIG 3.

However, note that the bundled tariff charged to electricity customers may vary due to the revenue cap arrangements that will apply for the Transmission business entity, the System Operator entity and/or the Single Buyer entity, or the Actual Cost arrangements applying to the Single Buyer entity.

3.3 Transmission

Transmission will operate under a Revenue Cap regime. Any annual revenue shortfall or surplus will be recovered or passed on to electricity customers in the next regulatory term to the final bundled price which is charged by Customer Services.

3.4 System Operations

System Operations will operate under a Revenue Cap regime. Any annual revenue shortfall or surplus will be recovered or passed on to electricity customers in the next regulatory period to the final bundled price which is charged by Customer Services.

3.5 Single Buyer

The Single Buyer will operate under a Revenue Cap regime for its own operating costs, combined with an Actual Cost regime for generation specific costs.

Under the Actual Cost regime, the Single Buyer will pass on all actual costs of procuring electricity from the IPPs and SESB Generation including fuel (gas, MFO & distillate), capacity payments and other costs associated with the terms and conditions of the PPAs, SLAs and other fuel procurement contracts to Customer Services. The Single Buyer will also include in its actual cost of procuring electricity from renewable generation and all other non IPP and SESB generation entities. These costs will then flow through to electricity customers via the bundled tariff. Actual Cost adjustments will occur on a six monthly basis.

RIG 2

Define Tariff Setting Framework

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The Single Buyer acts like a clearing house in the absence of a market pool and optimises generation costs based on efficient dispatch of generation. In a market pool model, the retailer pays actual pool costs. Therefore, the concept of subjecting the Single Buyer to an Actual Cost regime is similar to a market mechanism, where market price is set based on dispatch. The difference in the proposed Actual Cost regime for the Single Buyer is that generators get compensation based on actual cost of generation based on dispatch and contracts, rather than a marginal price of generation. This proposal is similar to a cost base pool, which operates in some countries.

Other operational and capital related costs of running the Single Buyer operations (including an allocation of joint costs (if any) will be subject to a Revenue Cap regime. Any revenue shortfall or surplus will be recovered or passed on to electricity customers in the next regulatory term to the final bundled price which is charged by Customer Services.

4. Worked example

In this scenario consider the final bundled average tariff to be 25 sen/kWh. This comprises of 10 sen/kWh for Customer Services, 4.8 sen/kWh for Transmission, 0.2 sen/kWh for System Operations and 10 sen/kWh for the Single Buyer. The 10 sen/kWh average tariff for the Single Buyer comprises 9.8 sen/kWh for generation specific costs (including fuel etc) subject to an Actual Cost regime, and 0.2 sen/kWh for other operational and capital costs subject to a Revenue Cap regime.

The final bundled average tariff of 25 sen/kWh has been based on the cost forecasts of the various business entities and 100 kWh forecasts of electricity sales. The forecast revenue position for all business entities is shown in the table below.

FIG: Forecast revenue and sales

	Bundled	Customer Services	Transmission	System Operations	Single Buyer Generation specific	Operational
Sales forecast (kWh)	100	100	100	100	100	100
Average Tariff (sen/kWh)	25	10	4.8	0.2	9.8	0.2
Revenue Forecast (RM)	25	10	4.8	0.2	9.8	0.2

If the actual electricity sales are equal to forecast and the actual costs of the Single Buyer are same as forecast costs, then all business entities are revenue neutral. Under this scenario, there will be no change to the following year's bundled average tariff.

Now consider the scenario where actual outcome is different to forecast as follows:

- actual electricity sales are 110 kWh, 10 kWh higher than forecast; and
- actual cost of single buyer is higher by RM 0.7, due to higher sales requiring additional generation.

Under this scenario, the revenue position of each Business Entity is the following.

FIG: Actual revenue and sales

	Bundled	Customer Services	Transmission	System Operations	Single Buyer Generation specific	Single Buyer Operational
Actual Sales (kWh)	110	110	110	110	110	110
Average Tariff (sen/kWh)	25	10	4.8	0.2	9.8	0.2
Actual Revenue (RM)	27.5	11	5.28	0.22	10.78	0.22
Forecast revenue (RM)	25	10	4.8	0.2	9.8	0.2
Revenue cap / Actual (RM)		N/A Price Cap	4.8 Revenue Cap	0.2 Revenue Cap	10.5 Actual Cost	0.2 Revenue cap
Surplus / (deficit) RM	0.8	0	0.48	0.02	0.28	0.02

In this scenario:

- the Customer Services business entity is allowed to retain the surplus of RM 1 as it operates under a Price Cap regime;
- the Transmission business entity over recovers by RM 0.48. As Transmission operates under a Revenue Cap this must be returned to customers in the following regulatory term;
- the System Operations business entity over recovers by RM 0.02. As System Operations operates under a Revenue Cap this must be returned to customers in the following regulatory term;

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Define Tariff Setting Framework

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- the actual costs of the Single Buyer with respect to generation specific costs (fuel etc) were RM 10.5 due to increased generation, RM 0.7 higher than expected. Given that the generation specific tariff recovered RM 10.78, the generation specific tariff over recovered by RM 0.28. This must be returned to customers in the following regulatory term¹; and
- the other operations of the Single buyer over recovered by RM 0.02. As this part of the Single Buyer is subject to a Revenue Cap, this must be returned to customers in the following regulatory term.

The total system over recovery is therefore RM 0.8 (plus interest) and is passed back to electricity customers through a reduction in the average bundled tariff and the relevant components of the average bundled tariff for the next year of the Regulatory Term. If this adjustment occurs in the last year of the regulatory term, then this tariff adjustment will be carried forward to the first year of the next Regulatory Term.

5. Tariff Adjustment Period

Under the proposed revenue cap and actual cost arrangements for the Transmission, System Operation and Single Buyer business entities, the periods of tariff adjustment are as follows:

- **Transmission revenue cap adjustments:** It is proposed that this adjustment is done on regulatory term basis;
- **System Operations revenue cap adjustment:** It is proposed that this adjustment is done on regulatory term basis;
- **Single Buyer Generation actual cost adjustment (for the generation specific tariff component):** It is proposed that this adjustment is done every six months; and
- **Single Buyer Operations revenue cap adjustment (for the other operational costs specific tariff component):** It is proposed that this adjustment is done on regulatory term basis.

It is proposed that these tariff adjustments are done based on audited financial statements. Therefore, there will be a lag of a few months before these tariff adjustments are finalised and implemented. It is therefore proposed that the tariff adjustments are interest adjusted to incorporate the time value of money. The interest rate for calculating the time value of money will be set at an appropriate rate, taking into consideration the length of the lag.

¹ Under the proposed regulatory framework, the generation specific costs of the Single Buyer will be adjusted every six months. The worked example reflects adjustment in regulatory period for simplified illustration of the Revenue Cap and Actual Cost arrangements.

Where forecasts of actual costs or revenues need to be made to make the adjustments, any error made in the forecasts will be compensated for at the next adjustment.

6. Regulatory Term

The Regulatory Term is the period (in number of years) regulated business entities operate under a Price Cap, Revenue Cap, or Hybrid regime with no review of either average set prices or allowable set revenues.

For example, under a Price Cap regime which operates for a five year Regulatory term, the set average price and path does not change with actual sales or actual expenditure (both capital and operating) outcomes. The business entity operates for the Regulatory term under initial Price Cap forecasts. This places strong incentives upon the business entity to seek efficiencies in cost and improve utilisation as it largely retains these efficiencies. The efficiency framework is discussed in Regulatory Guideline Number 3 (RIG 3).

The longer the Regulatory Term the greater the reliance on forecasts and the stronger the incentives for the business. The Regulatory term is set at five years for Transmission and Distribution in UK, Australia and Singapore.

A fixed Regulatory Term also provides certainty of revenue to regulated businesses and generally lowers regulatory and revenue risk (if coupled with the right incentive framework).

6.1 Recommendation on Regulatory Term

ST is recommending a Regulatory Term of three (3) years, as applied in Peninsular Malaysia. This is shorter than a five (5) year Regulatory Term applicable in Australia, UK and Singapore, because it is the first time the Regulatory Term concept will be applied in Sabah. As the ST gets more comfortable with forecast and cost data it will consider increasing the Regulatory Term to 5 years.

ANNEX C

REGULATORY IMPLEMENTATION GUIDELINE 3 - RIG 3 -

Sets the revenue requirement principles for each business entity (building block model) & establishes incentive framework: clear principles for treating variances in forecasts (both cost and consumption)



1. Objective

The objectives of RIG 3 are as follows:

- Establish the revenue requirement principles for each of the five SESB business entities¹; and
- Establish the incentive framework for the five SESB business entities¹.

2. Principles of Revenue Requirement

Revenue requirement in this context is defined as the forecast revenue which each of the five SESB business entities should recover from electricity customers (through electricity tariffs). The revenue requirement should enable the business entity to meet its operational expenditure requirements, invest in new assets, pay relevant taxes and deliver a market based efficient return to investors of the business entities (both debt and equity investors).

The annual revenue requirement for each year of the Regulatory Term must consist of the following:

- **Forecasts of efficient operating costs;**
- **A return on the Regulatory Asset Base (RAB).** The RAB is the average of starting and closing fixed assets. The return on RAB must reflect an efficient market based cost of capital²;
- **Forecasts of efficient depreciation;**
- **Forecast tax payments;** and
- **An allowance for efficiency carryover amounts.**

The ST will provide to SESB a Revenue Requirement Model (Model). The Model will describe in detail the data requirements for each of the SESB business entities and the calculation of revenue requirements.

¹ The five SESB business entities are specified in RIG 1.

² Cost of capital is further discussed in RIG 4.

3. Revenue Requirement for Customer Services, Transmission, Single Buyer Operations and System Operations

The four business entities of SESB share a common approach to setting their Annual Revenue Requirements (ARR), which is outlined below:

$$\mathbf{ARR^3 = Return\ on\ regulated\ assets\ (Return\ * RAB) + Forecast\ annual\ depreciation + Forecast\ annual\ operating\ costs + Forecast\ annual\ tax\ payments + Efficiency\ carryover\ amount}$$

The various components of the ARR are discussed below.

3.1 Return on Regulated Assets

The return component should deliver an efficient market based return to investors in the business entities. Specifically the return on ratebase (RORB) is calculated as the forecast market return multiplied by the RAB.

3.1.1 Forecast Market return

The forecast market return is set as the nominal after tax weighted average cost of capital (WACC) and is discussed comprehensively in RIG 4. The formula for determining WACC is listed below:

$$\mathbf{WACC = (Rf + Dm) * (1 - Tc) * G + (Rf + Be * MRP) * (1 - G)}$$

Where

Rf = Risk free rate

Dm = Debt margin

Tc = Tax rate

G = Gearing, measure as Debt / (Debt + Equity)

Be = Equity Beta

MRP = Market risk premium

The WACC parameters are discussed in RIG 4.

³ Interest payments are not included in the calculation as return to debt providers (or interest) is incorporated in the return or WACC parameter.

3.1.2 Forecast RAB

The RAB for the first year of the Regulatory term is the average of the starting asset value and the closing asset value for that year. There are various options for establishing the starting asset value including historic cost, optimal deprival value and optimised depreciated replacement cost (ODRC). While it is not the intent of RIG 3 to determine which is the most appropriate method to set starting asset values for the SESB business entities, regulators internationally have adopted a range of options including historic cost and an ODRC estimate. For example, the Energy Market Authority (EMA), the electricity regulator in Singapore has adopted historic cost⁴. In particular, the ST is of the view that land asset values should be based on historic cost or book value, as opposed to any revaluation.

Once the starting asset value is determined, it is intended not to review these starting asset values as it lowers regulatory risk by promoting revenue stability and certainty for the business entities.

The starting asset value includes only fixed assets such as land, plant and equipment, used for supplying electricity to customers (either directly or indirectly). The asset values explicitly do not include other assets such as cash, financial assets, investment in subsidiaries, tax assets intangibles and goodwill. The starting asset values are net of upfront customer contributions or capital received from Governments in the form of Government grants or subsidies.

Once the starting asset base is determined, the forecast RAB is set based on the following formula:

$$\mathbf{RAB} = \mathbf{Average\ of\ starting\ asset\ value\ and\ closing\ asset\ value}$$

Where;

$$\mathbf{Closing\ asset\ value} = \mathbf{Starting\ asset\ value} - \mathbf{annual\ depreciation} + \mathbf{forecast\ capital\ expenditure}$$

Capital expenditure forecasts are in nominal Ringgit Malaysia (RM), consistent with the nominal WACC definition. In reviewing capital expenditure forecasts, the ST will test for efficiency and prudence of expenditure forecasts by:

- reviewing the efficiency of the underlying asset management, development and replacement policies;
- ensuring consistency between the expenditure forecasts and efficient asset policies; and

⁴ Condition 22, Clause 5 of the Electricity Licence For Transmission Licensee. Electricity Transmission Licence issued by EMA to SP PowerAssets Limited.

RIG 3

Establish Revenue Requirement Principles

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- ensuring consistency between capital expenditures and macroeconomic factors including sales and demand growth.

For all business entities **except** Single Buyer Generation, besides the fixed assets as stated above, the starting asset value will also include the net working capital calculated as follows:

<i>Item under Working Capital Requirement</i>	<i>Basis</i>
<i>Account Receivable</i>	<i>30 days of electricity sales</i>
<i>add Strategic Spares</i>	<i>5% of Operation & Maintenance costs</i>
<i>add Minimum Cash Requirement</i>	<i>30 days of Cash Operating Requirement</i>
<i>less Trade Payable</i>	<i>30 days of PPA & SLA cost (Capacity & Energy Charges)</i>
<i>Net Working Capital Requirement to be included in RAB (except SB Generation)</i>	

3.2 Depreciation

Annual depreciation will be based on the efficient economic life of assets. In determining the efficient economic life for various asset classes (such as transformers, poles, sub stations, switchgear etc), the ST will benchmark with other utilities to ensure that the useful life assumptions are consistent with best practice. The ST will also consider obtaining an independent engineering estimate of useful life for the various asset categories.

Once the useful life estimates are finalised, annual depreciation forecasts will be based on a straight line basis.

3.3 Forecast operating costs

In determining efficient operating cost, the ST will test for efficiencies through benchmarking (where relevant), a review of historical cost performance and the efficiency and prudence of asset management policies.

Where operating cost forecasts include cost of services procured from related parties⁵, these related party costs will only be incorporated in efficient operating cost forecasts if:

- these related party transactions are entered into on an arm's length basis through competitive tendering; or

⁵ The definition of Related Party is as per the Financial Reporting Standard 124 as set by the Malaysian Accounting Standards Board (MASB).

- these related party costs contain no margin or profit and purely reflect the direct cost of providing these services and the cost is efficient; or
- it can be demonstrated that these related party costs are comparable to market benchmarks (assuming that there are several alternative market service providers for the relevant services).

3.4 Forecast tax payments

Annual tax payments will be based on a calculation of forecasts of taxable income and the applicable tax rates. Taxable income will be based on the forecasts of return on assets, operating costs, efficiency carryover amounts and capital allowances.

Capital allowances will be based on the applicable capital allowances rates as per the current and relevant Malaysian Tax Guide. Any tax losses incurred in any year of the Regulatory Term will be carried forward and offset future tax liabilities.

3.5 Efficiency carryover amounts

Efficiency carryover amounts will be determined based on the efficiency carryover scheme. The efficiency carryover scheme operates in addition to the Base Incentives inherent in the proposed regulatory framework. Both the Base Incentives and the efficiency carryover scheme will operate in conjunction with the set Variance Thresholds. Variance Thresholds are discussed in Section 7.1.1.

3.5.1 Base Incentive

The Base Incentives enable the business entities to retain any variances between actual operating and capital expenditure amounts relative to forecasts within the Regulatory term. This will encourage the pursuit of efficiencies in both operating and capital expenditures, as reductions in any expenditure as a result of efficiencies will result in higher return for shareholders. Cost savings should not result in deterioration of network performance or customer service. The business entity will have to provide on an annual basis a comprehensive analysis of the variances between actual expenditure and forecasts. The ST will consider implementing a network performance and customer service scheme⁶, to ensure that deterioration in network and customer service standards result in financial penalties.

⁶ To be developed in RIG 6

RIG 3

Establish Revenue Requirement Principles

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The ST will also consider setting upper and lower variance bands around capital and operating cost variances to ensure the benefits (or the risk) of major cost variances due to forecast errors are not retained by the business entity⁷.

3.5.2 Efficiency carryover scheme

The purpose of the efficiency carryover scheme (ECS) is to provide the business entities a continuous and sustained incentive to pursue cost efficiencies during every year of the Regulatory Term. This is important as under the base incentive regime, the business entities incentive to pursue efficiencies weaken as they approach the end of the Regulatory Term. This is because cost efficiencies will result in a lower cost base for the subsequent Regulatory Term and the time to retain efficiencies during the current Regulatory Term reduces with every passing year of the Regulatory term.

The ECS is designed to provide sustained incentives to pursue efficiencies in operating expenditures. The ECS will operate as follows:

- Towards the end of the Regulatory Term, actual operating expenditure for all years (as per the regulatory accounts⁸, except for the last year which will be based on estimates reflecting year to date expenditures) will be compared to the forecast operating expenditure which was adopted to set annual revenue requirement⁹.
- The total variance between actual operating expenditure and the regulatory operating expenditure estimates (Cost Efficiency Amount) will be quantified.
- 50% of the Cost Efficiency Amount (Sharing Cost Amount) will be added on to the annual revenue requirement projected for the next Regulatory Term as follows
 - 50% of the Sharing Cost Amount to be added to the first year of the new Regulatory Term
 - 30% of the Sharing Cost Amount to be added to the second year of the new Regulatory Term
 - 20% of the Sharing Cost Amount to be added to the third (and last) year of the new Regulatory Term
- The difference between the actual operating expenditure and the estimated operating expenditure for the last year of the Regulatory term will be taken into account (adjusted for interest) when calculating the Cost Efficiency Amount for the subsequent Regulatory Term.

⁷ This is further discussed in Section 7: Incentive Regime

⁸ The framework for developing regulatory accounts is outlined in RIG 10

⁹ The setting of revenue requirement is outlined in Section 3 of this RIG

A worked example is presented below and assumes that cost efficiencies of 20 are achieved every year of the First Regulatory Term.

Fig: Example of the ECS (expenditure amounts are in RM)

	First Regulatory Term			Second Regulatory Term		
	Year 1	Year 2	Year 3	Year 1	Year 2	Year 3
Operating expenditure forecast	120	120	120	100	100	100
Actual operating expenditure	100	100				
Estimated operating expenditure			100			
Annual cost efficiency	20	20	20			
Cost Efficiency Amount						60
Sharing Cost Amount						30
Efficiency Carryover Amount %				50%	30%	20%
Efficiency Carryover Amount				15	9	6
ARR Operating expenditure forecast	120	120	120	115	109	106

The Efficiency Carryover Amounts are RM 15 for Year 1, RM 9 for Year 2 and RM 6 for Year 3 for the Second Regulatory Term.

The Operating expenditure forecast will reduce from RM 120 to RM 100 for the Second Regulatory Term based on the cost efficiencies achieved. Allowing for the Efficiency Carryover Amounts, the Annual Revenue Requirement (ARR) Operating expenditure forecast reduces from RM 120 to RM 106 by year three of the Second Regulatory Term.

Customers benefit as the total cost has been reduced. The business entity has benefitted from the incentive mechanism as it has firstly retained cost efficiencies in the First Regulatory Term and carried forward 50% of the cost efficiencies to the Second Regulatory Term.

4. Revenue Requirement for Single Buyer

The Single Buyer purchases electricity from the IPPs based on PPAs and from SESB Generation based on SLAs and Non-SLAs (including non-grid).

The revenue requirement for the Single Buyer for the Regulatory Term comprises of the following:

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- Cost of electricity purchases based on the contractual terms (capacity payments, other fuel and other variable costs) and forecast dispatch (subject to an Actual Cost regime) as set out in the Single Buyer Rules developed by ST. SESB to ensure that its procurement processes and contracts with respect to fuel procurement (particularly MFO and Distillate) are consistent with principles of economic efficiency stated in the Single Buyer Rules. The current market price of fuels will be used to derive the base tariff. The changes to the price of fuels will be incorporated in the Imbalance Cost Pass-Through Mechanism as outlined in RIG 8; and
- The ARR calculated based on the methodology as outlined in Section 3 to recover all operational and capital costs of the Single Buyer (subject to a Revenue Cap Regime).

5. Converting Revenue Requirement to Average Tariffs

Once the Annual Revenue Requirements (ARR) for the Regulatory Term has been determined, the next step is to set Average Component Tariffs for SESB business entities and an average electricity tariff for electricity customers. The key principle for setting the Average Component Tariffs for the SESB business entities is to ensure that the set tariffs over the Regulatory Term recovers the total ARR over the Regulatory Term on a Net Present Value (NPV) basis.

The total average electricity tariff is the sum of all Component Average Tariffs for each of the SESB business entities. This is shown below:

$$\text{Total average electricity tariff} = \text{Customer Services Tariff} + \text{Transmission Tariff} + \text{System Operations Tariff} + \text{Single Buyer Tariff (generation specific tariff + other operating cost specific tariff)}$$

Presented below is a worked example, where the ARR for a SESB business entity is RM 100 for every year of the Regulatory term, forecast electricity sales (as measured by customer metered sales) is assumed to be 50 kWh growing by 3% per annum, WACC of 8.5% and starting price of RM 1.80/kWh.

Fig: Example of the setting the average Component Average Tariff for the SESB business entities

		First Regulatory Term		
		Year 1	Year 2	Year 3
Annual Revenue Requirement (RM)		100	100	100
WACC	8.5%			
NPV of ARR (RM)	255			
Forecast electricity sales (kWh)		50	52	53
Starting Price, Po (RM/kWh)	1.80			
Price escalation (X Factor)		4.0%	4.0%	4.0%
Forecast Price (RM/kWh)		1.87	1.95	2.02
Forecast revenue (RM)		94	100	107
NPV of forecast revenue (RM)	255			
NPV difference	0			

In this example, the forecast Component Average Tariff has to increase by 4% per annum to ensure the recovery of the ARR over the Regulatory Term on an NPV basis. This is achieved by setting the Price escalation factor (X-Factor) at 4% per annum.

5.1.1 Price control equations

There will be 6 Price Control Equations:

1. The Customer Services Price Control Equation (CS PCQ), which will set the Customer Services Tariff;
2. The Transmission Price Control Equation (T PCQ), which will set the Transmission Tariff;
3. The System Operations Price Control Equation (SO PCQ), which will set the System Operations Tariff;
4. The Single Buyer Generation Price Control Equation (SBG PCQ), which will set the Single Buyer generation specific tariff;
5. The Single Buyer Operations Price Control Equation (SBO PCQ), which will set the Single Buyer other operating cost specific tariff; and
6. The Average Electricity Tariff Price Control Equation (AE TPCQ), which will set the total average electricity tariff and will be a sum of the first five Price Control Equations.

The details of the 6 Price Control Equations and the AE TPCQ will be specified in the Model. The general form of the Price Control Equations is set out below:

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Customer Services will be subject to a pure Price Cap, in accordance with the following Price Control Equation:

$$P_t = P_{t-1} * (1 + X_t)$$

Where;

- P_t = The price cap in the relevant year
- X_t = The X Factor, which reflects a pre-determined annual change in prices to meet the revenue requirement (X may be zero to maintain a consistent price level over the Regulatory Term)
- P_{t-1} = P_o , for the first year of the Regulatory Term

The Transmission business entity, System Operations business entity and the Single Buyer Operations business entity are subject to Revenue Cap regimes. The individual Revenue Cap Equations will be in the following form:

$$R_t = R_{t-1} * (1 + X_t) + K_t + K_{t-1}$$

Where;

- R_t = The revenue requirement in the relevant regulatory term
- X_t = The X Factor, which reflects a pre-determined annual change in prices to meet the revenue requirement (X may be zero to maintain a consistent price level over the Regulatory Term)
- R_{t-1} = R_o , for the first Regulatory Term
- K_t = Correction for Single Buyer, Transmission and System Operations Revenue Cap adjustments for the previous regulatory term (in the first Regulatory Term, $K_t = 0$)¹⁰
- K_{t-1} = Correction for forecasting error in Revenue Cap adjustments made in the previous regulatory term (in the first and second Regulatory Term, $K_{t-1} = 0$)

The adjustment factors for the Revenue Caps will be calculated as follows:

$$K_t = R_{t-1} - RE_{t-1}, \text{ and}$$

$$K_{t-1} = RE_{t-2} - RA_{t-2}$$

Where;

- RE_{t-1} = Estimated actual revenue for the previous regulatory term
- RE_{t-2} = Estimated actual revenue for the regulatory term before the previous regulatory term
- RA_{t-2} = Actual revenue for the regulatory term before the previous regulatory

¹⁰ The operation of the cost and revenue adjustments are outlined in RIG 2

term
Note: In the first Regulatory Term, $K_t = 0$
In the first and second Regulatory Term, $K_{t-1} = 0$

6. Tariffs for electricity customers

Electricity tariffs for electricity customers will be set by Customer Services. Customer Services will set electricity tariffs for customer segments (such as domestic, commercial, industrial etc), such that the forecast revenue divided by the forecast electricity sales equals the total average electricity tariff as per the Average Electricity Tariff Price Control Equation.

The annual process of setting electricity tariffs by Customer Services is described in RIG 9.

7. Incentive Regime

In the proposed incentive-based regulatory regime, there are three types of incentives. These are:

7.1 Cost Incentives

The SESB business entities are incentivised to pursue efficiencies in operating and capital expenditures. These incentives have been discussed in Section 3 and comprise of the Base Incentive and the ECS.

To account for significant forecast error, the ST will set safeguards (or Variance Thresholds) for the first Regulatory Term. Once the ST gains confidence in the accuracy of forecast data, it will consider removing the Variance Thresholds.

7.1.1 Variance Thresholds

The Variance Threshold will be set at 25% for both operating and capital expenditure. If annual operating or capital expenditure varies by more than 25% of forecasted values, then the ECS will not apply for that year. Furthermore, the ST will consider adjusting the AAR amounts and the relevant Price Control Equations to correct for forecasting error.

In determining any adjustments to subsequent years AAR amounts, the ST will take into account any actual cost efficiencies achieved by the SESB business entities.

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7.2 Financial incentives

The SESB business entities' return is based on a benchmark efficient WACC. Therefore if they are able to structure their capital requirements (both debt and equity) such that the actual cost of capital is lower than the regulated WACC, the financial benefit is retained by the business entities.

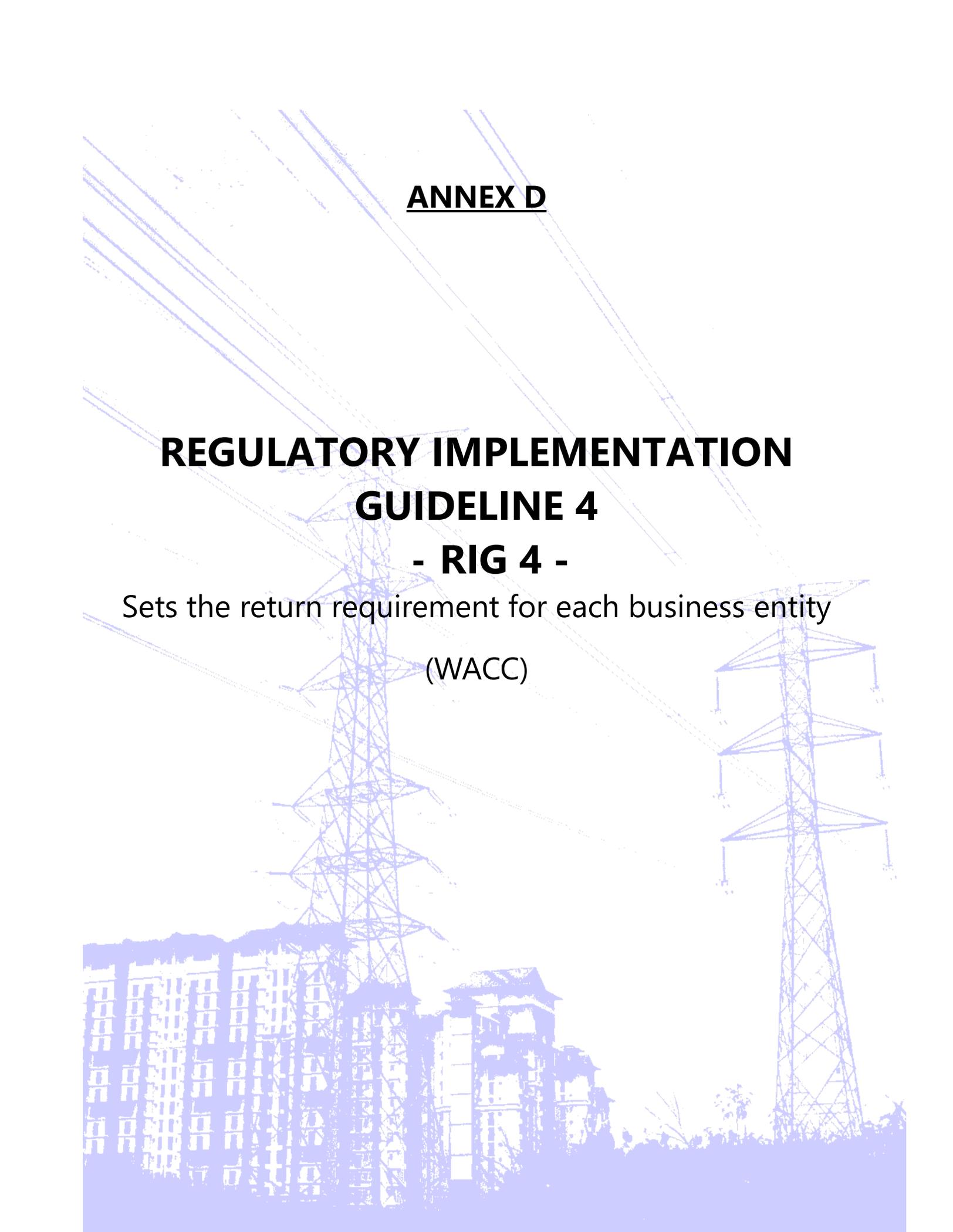
The setting of a regulated return based on an efficient WACC is presented in RIG 4.

7.3 Network performance and customer service incentives

As discussed earlier, savings in operating and capital expenditure should not result in deterioration in network performance or customer service. Therefore, the EC will consider implementing a network and service performance scheme to incentivise improvements in network performance and customer service.

Under the scheme, the ST will consider setting targets for both network performance (such as SAIDI, SAIFI for Customer Service and availability for Transmission) and customer services (such as connection time, call centre performance). The SESB business entities will be rewarded for exceeding the targets (by increasing prices to customers) and penalised for not meeting set targets (reducing prices to customers).

This scheme is discussed in RIG 6.

The background of the slide features a photograph of several high-voltage electrical transmission towers and power lines stretching across the sky. Below the towers, a cityscape is visible, including a prominent multi-story building with a clock tower. The entire image is overlaid with a semi-transparent blue grid pattern.

ANNEX D

**REGULATORY IMPLEMENTATION
GUIDELINE 4**

- RIG 4 -

Sets the return requirement for each business entity

(WACC)

1. Objective

The objective of RIG 4 is to outline the guidelines the ST will adopt in determining the appropriate weighted average cost of capital (WACC) for the SESB business entities.

2. Overview of WACC

Companies finance their investments through a combination of equity and debt. WACC represents the weighted average cost of equity and debt.

In efficient competitive markets, efficient organisations are generally expected (over the long term) to earn a rate of return at least equal to their WACC. If the actual return is too low, a firm will find it difficult to finance investments and may face insolvency or takeover. If the return is too high, then the organisation faces increased competitive threat (where competitors and/or new entrants will over time force returns down to their efficient level).

In non-competitive markets, where prices for services are determined by Government or an industry regulator, prices are set based on delivering an efficient return to the regulated entity. A key element of determining this efficient return in the absence of a market based approach to pricing is to set efficient levels of recoverable expenditure and an efficient, market based cost of capital or WACC.

The ST will adopt the following principles in determining the appropriate WACC for the SESB business entities.

2.1 Efficiency

The WACC and the WACC parameters must be set on an efficient basis. This implies that the WACC must provide an efficient return to the regulated entities and deliver efficient prices to customers. In ensuring efficiency, the ST will ensure that the WACC for the SESB business entities:

- is based on an efficient capital structure and credit rating;
- reflects market based returns on debt and equity;
- adequately reflects regulatory and market risk; and
- there is consistency between all the WACC parameters and the underlying cash flows calculated in the determining the ARR for the relevant SESB business entities.

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2.2 Market data and trends

In setting the WACC the ST will ensure (where appropriate) that the analysis is based on Malaysian capital markets (both debt and equity). If data for the Malaysian market is unavailable either due to lack of sufficient history or liquidity, then international market data will be used as a reference point and translated into a Malaysian context. However, due to current SESB operation which are unable to source it funding from capital market, for this exercise the ST is considering using Government Soft Loan as currently practiced to fund SESB's capital expenditure.

2.3 International best practice

The ST will consider (where possible) relevant international regulatory precedence. However, due to current SESB financial position, the practice currently used in implementing IBR in TNB particularly on regulatory WACC decision will be taken into account in the ST's analysis for SESB.

3. WACC definition

Various forms of WACC models exist. In particular, there are numerous models and approaches for deriving the cost of equity component of the WACC. For regulatory purposes, the most common approach to calculating the cost of equity is the Capital Asset Pricing Model (CAPM). Alternative forms of CAPM model exist too. One of the key differences across WACC and CAPM models is the treatment of taxation (i.e. how taxes may affect company and/or investor cash-flows) and inflation. The figure below shows the various model of WACC with different assumptions on inflation and taxation.

Fig: Examples of WACC

Taxation	Pre-Tax Real	Pre-Tax Nominal
	Post-Tax Real	Post-Tax Nominal
	Post-Tax Real (Vanilla)	Post-Tax Nominal (Vanilla)
Impact of Inflation		

All these models are appropriate and with the consistent cash flows will result in similar prices and business NPVs. However, the model choice has implications on complexity of

calculation and subsequent adjustment to standard accounting systems and reports. For example, if a real WACC model is adopted, nominal accounting information has to be adjusted to real terms (as accounting information is nominal). Similarly, if an after tax model (post tax) is chosen, tax calculations based on tax accounting need to be conducted and adjustments may be required (if a post tax nominal model is adopted) to exclude the tax shield on interest from the tax calculations.

In recommending the appropriate model for WACC, the ST notes that TNB, SESB and GMSB have used the nominal post tax WACC model (and CAPM for cost of equity) in their analysis.

The ST therefore recommends that the post tax (text book) nominal WACC be used to ensure consistency and simplicity and that the capital asset pricing model (CAPM) be used to estimate the cost of equity. Other models to determine cost of equity such as the arbitrage pricing model and forward looking dividend growth models are more controversial (as many more assumptions are required) and less used in regulatory settings.

The ST recommends the use of the nominal after tax text book WACC definition, as outlined below.

Fig: Nominal after tax WACC

$$WACC = (R_f + D_m) * (1 - T_c) * G + (R_f + B_e * MRP) * (1 - G)$$

Where

R_f = Risk free rate

D_m = Debt margin

T_c = Tax rate

G = Gearing, measure as Debt / (Debt + Equity)

B_e = Equity Beta

MRP = Market risk premium

4. Setting of WACC parameters

This section outlines the approach the ST will adopt in setting the various WACC parameters.

4.1 Risk free rate (Rf)

The Risk Free Rate represents the return investors require investing in a risk free or close to a risk free asset.

Therefore there are three choices to be made in setting the risk free rate.

- The first is to determine the type of risk free asset;
- The second is to determine the term to maturity of the risk free asset; and
- The third is to determine the exact calculation of the risk free rate, once the risk free asset and the term to maturity are determined.

Defining the risk free asset

As we are determining the WACC in a Malaysian context, the appropriate risk free asset should reflect return investors require to invest in Malaysian Government Securities (MGS). Investing in MGS reflects sovereign risk and will be considered (by investors) the safest underlying and stand alone (without any credit enhancements or credit wraps) investment in Malaysia.

The choice of using the local government bond yield as the risk free rate is consistent with regulatory practice in Australia, UK, Singapore and New Zealand. Although several attempts have been made to determine WACC and indeed risk free rate using a global portfolio, regulators have chosen to stick to the bond yields and market data of their respective countries. Global WACC and consequently global risk free rates and other global parameters are still being discussed with several issues to be resolved such as defining the composition of the global market, the nature and tax status of the marginal global investor, access to the global portfolio, differences in exchange and interest rate setting frameworks etc.

Term to maturity of risk free asset

Establishing the term of the risk free rate is perhaps more controversial. This is because the longer the term, the higher the rate (given a normal upwardly sloping yield curve). Theoretical, the term of the risk free rate should be based on the life of the underlying asset. Generally, jurisdictions opt for a longer duration (say 10+ years), as this is more consistent with the prudent borrowing practices for organisations with long life assets. Regulators in Australia (Australian Energy Regulator) have adopted the yield of a 10 year Australian government bond and the Energy Market Authority (EMA) has chosen the yield on a 20 year Singapore government bond to set risk free rates for determining regulatory WACC.

The ST's preference is to adopt the yield on the Malaysian Government Securities with term to maturity of between 10 to 20 years as the appropriate risk free rate for setting WACC for the SESB business entities.

Calculating the yield on the risk free asset

The ST considers it prudent to take a five year historical average of the 10 to 20 year yield on the MGS to set the regulatory WACC. This is because the market for the MGS is not as deep or as liquid as other international benchmarks (such as Australia and UK) and short term market conditions can have a significant impact on current yields.

The Australian Energy Regulator takes a 20 day historical average to set the risk free rate, whilst the UK regulator takes a longer term historical average (5 to 10 years) and also considers current rates.

The ST will set the risk free rate based on the relevant historical average and current yields on 10 to 20 year MGS at least two months prior to the start of the first Regulatory Term.

4.2 Debt margin (Dm)

In establishing the cost of debt, efficient debt levels (Gearing) and the cost of debt has to be established. The cost of debt is the risk free rate plus the debt margin that an efficient utility would have to pay to finance its debt. In setting the debt margin the ST has to determine the appropriate efficient credit rating and the term to maturity of the debt portfolio. In general, the debt margin, or the spread above the risk free rate increase as rating deteriorates (reflecting additional default risk) and increased term to maturity (given a normal upward sloping yield curve).

Establishing credit rating

The ST considers that a utility such as SESB, whose operations have a significant impact on the economy of Malaysia, should be rated at least investment grade. This approach is also consistent with the approach adopted by ST in setting up the WACC for TNB in Peninsular Malaysia.

The ST recommends the setting of an efficient debt margin based on an implied investment grade rating of BBB+ (based on S&P credit ratings). The ST notes that BBB+ translates to credit rating of AA as determined by RAM Holdings Berhad.

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Term to maturity of debt portfolio

The term to maturity of the debt portfolio, should reflect the term of the risk free rate (for consistency in WACC calculations) and be consistent with the long life assets. However noting that the debt portfolio will comprise of both short and long dated bonds and noting the lack of liquidity and depth of long dated corporate debt issues in Malaysia, the ST recommends that the average maturity of an efficient debt portfolio be set at ten years.

This is consistent with the approach adopted by ST for TNB in Peninsular Malaysia which set debt rate based on the yield of ten year debt maturity.

Calculating debt margin

The ST recommends that the debt margin (margin above yield of MGS) on ten year corporate bonds with a rating of BBB+ (S&P estimate) or AA (RAM estimate) be set based on a historical five year average. This is consistent with the setting of the risk free rate.

4.3 Gearing (G)

Gearing represents the amount of debt as a percentage of total capital (debt plus equity). In establishing efficient gearing levels, the ST has considered international practice in Australia, UK, Singapore, and New Zealand all jurisdictions which have implemented WACC based incentive regulation. The AER, EMA and Ofgem have set gearing levels at around 60% to set regulated WACC, consistent with the adoption of investment grade credit rating. The ST notes the inverse relationship between gearing levels and credit rating which implies a lowering of credit quality with an increase in gearing. The ST also notes Moody's published research (in 2009) which implies a credit rating of A3 consistent with gearing levels between 60% to 68% for UK utilities. However, given the IBR is already implemented in Peninsular Malaysia, it would be appropriate to set regulated WACC for SESB based on optimal gearing level as recommended for TNB.

Therefore the ST has decided to adopt a somewhat conservative gearing level of 55% to set regulatory WACC for the first Regulatory Term. The ST will in time as the incentive regulatory framework matures in Malaysia consider raising the gearing level to 60% more in line with efficient international benchmarks.

4.4 Equity beta (Be)

The equity beta is the central element of the CAPM in determining cost of equity and is an indication of the systematic riskiness attached to the returns on ordinary shares. It equates

to the asset beta for an ungeared firm, or is adjusted upwards to reflect the extra riskiness of shares in a geared firm, i.e. the Geared Beta or Equity Beta.

To determine the equity beta for a given firm for an efficient capital structure presents many challenges, some of which are discussed briefly below.

- The firm may not be listed and hence no firm specific stock market data exists. In this case, benchmark firms which are listed on the stock market can be used as a proxy. If the firm is listed, the period of beta estimation provides different results.
- Instability of beta estimates. As stock markets are volatile, beta estimates tend to be unstable with extreme market events (like the recent GFC, Asian financial crises and the dot com bubble) impacting stock markets sharply in a short space of time.
- The impact of leverage and taxes. According to most academics, equity beta increases almost linearly with leverage. However, there is often a disconnect between the accepted theoretical behaviour of equity beta and observed beta.
- Convergence to unity. There is some evidence that equity beta converges to one over a long period of time. This is referred to as the Blume Adjustment. The basis of this theory is that as a firm matures, it adjusts its products, markets, gearing and technology and therefore is able to converge to market risk. However, many regulators are now questioning the relevance of the Blume adjustment in determining regulatory WACC. This is because; unlike in competitive markets where firms have choice of products and capital structure, a regulated utility's product offering and capital structure are predefined in setting their regulatory WACC.

Regulators in Australia and UK have spent considerable time and effort on calculating betas for regulated electricity and gas businesses. In Australia, the national regulator AER has recently adopted an equity beta of 0.8, with gearing of 60%. This equity beta of 0.8 has fallen from the previously adopted value of 1, which had been the standard equity beta used by most Australian state regulators since 1994. Most equity beta calculations for UK and American utilities range from 0.8 to 0.5, for a gearing of 60%.

Given that SESB is not listed at Kuala Lumpur Stock Exchange (KLSE), the ST recommends that the beta for TNB (which is a listed firm) be used as a proxy for determining SESB's equity beta.

As an example, Bloomberg published an equity beta of 0.833 for TNB in December 2009, with a market gearing of 38%. This translated into an equity beta of 1.15 for a market gearing of 55%. The equity beta estimate of 1.15 for TNB is higher than equity beta estimates for regulated utilities in UK and Australia. This is expected, as the regulatory regime is well established in Australia and UK, which has resulted in lowering regulatory risk, resulting in lower cost of equity and equity beta estimates.

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Note that the specific circumstances of SESB (in particular, level of gearing) will be taken into account in providing an appropriate equity beta. However, for this regulatory period the ST will adopt adjusted equity beta of TNB to estimate the cost SESB's equity.

4.5 Market risk premium (MRP)

MRP represents the premium or extra return investors require to invest in risky assets above the risk free rate. There are two issues here. First the definition of the market and second the calculation of the MRP itself.

Most regulators adopt the stock market index of their respective country as a good proxy for the market. As mentioned earlier, defining a global market presents several challenges and remains a good theoretical concept at best with several issues to be resolved before being accepted a credible metric for regulators to adopt.

Once the market is defined, the methods of calculating MRP are the following

- **Historical analysis:** Most regulators have tended to adopt a historical calculation of the MRP a good starting point. For a historical analysis to produce a reliable estimate of MRP, typically regulators have required at least 50 years of reliable historical data. This is the most common method of establishing MRP for markets which have the required historical data.
- **Sovereign risk assessment:** There is a developing theory that equity market risk is influenced strongly by sovereign credit ratings. For example, investors will require a premium to invest in countries which have a lower rating and premiums for lower ratings can be developed based on assumed default rates.
- **Forward looking analysis:** A dividend growth model based on investor expectations of future market returns can be used to calculate MRP. This method is difficult to implement as several assumptions have to be made regarding investor expectation of long term returns and reliably interpreting analyst forecasts.
- **Benchmarking with other markets:** Typically more risky markets will tend to have a higher MRP. By comparing markets and their volatilities some assessment can be made for market which either lack historical data or lack coverage by analysts.

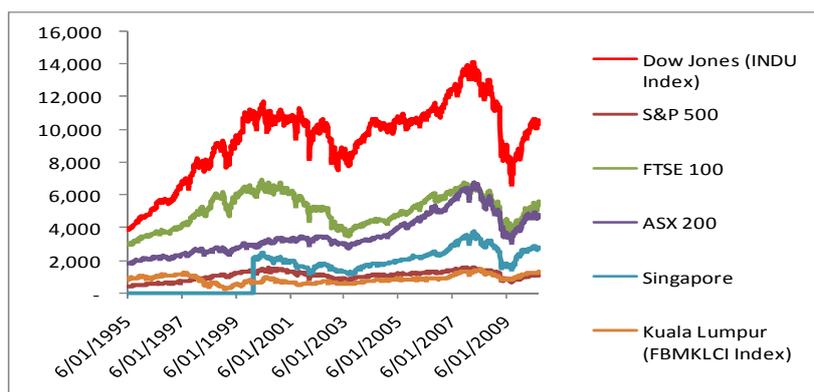
For calculating the MRP for Malaysia, the ST has chosen to rely on various published estimates, benchmarking with other markets and regulatory precedence. Unfortunately there is insufficient historical data to calculate a reliable base estimate of MRP for Malaysia.

Published estimates of Malaysian MRP: Various reliable estimates of the MRP for Malaysia have been undertaken, with estimates ranging from 7%¹ to 7.63%².

Regulatory precedence: International regulatory estimates of the MRP are 6.5% for Australia³, 7%+ for New Zealand⁴, 7% for Singapore⁵ and 4.5% for the UK⁶. Most estimates of the MRP are ‘backwards looking’ as they are based on past differences between market returns and the risk free return. The GFC has caused increased volatility in financial markets, and the MRP has increased as a consequence. Australia recently increased its MRP estimate from 6% to 6.5% as a result of the GFC. New Zealand is similarly considering increasing its (tax adjusted) MRP as a consequence of the GFC⁷.

Benchmarking with other markets: The ST also notes the historical performance of the FBMKLCI 30 with other international and Asian markets. The following figure shows that the FBMKLCI broadly moves in line with other major international indices like the Dow Jones, S&P 500, FTSE 100, ASX 200 and Singapore STI.

Fig: Market returns for stock market indices



However, the FBMKLCI is more volatile than the major international indices. This suggests that the MRP for Malaysia should be higher than the MRP estimates for Singapore (7%) and Australia (6.5%).

¹ By RHB

² By Damodaran. Website is <http://pages.stern.nyu.edu/~adamodar/>

³ AER; “Electricity Transmission and Distribution Network Service Providers - Review of the Weighted Average Cost of Capital (WACC) Parameters”; May 2009; p 238

⁴ This is a tax adjusted MRP to take into account New Zealand’s tax system for dividends (i.e. Brennan-Lally CAPM). It is likely the MRP for New Zealand would be closer to 6.5% if a more conventional CAPM were used.

⁵ EMA; “Review of the Parameters for Setting Vesting Price for the Period 1 January 2010 to 31 December 2010 – Draft Determination”; 9 September 2009; p 10

⁶ OFGEM; “Transmission Price Control Review – Documentation on the Financial Model”; October 2006 (Note, OFGEM utilised an Equity Risk Premium (Real) of 4.5% and at the time assumed inflation of 2.6%).

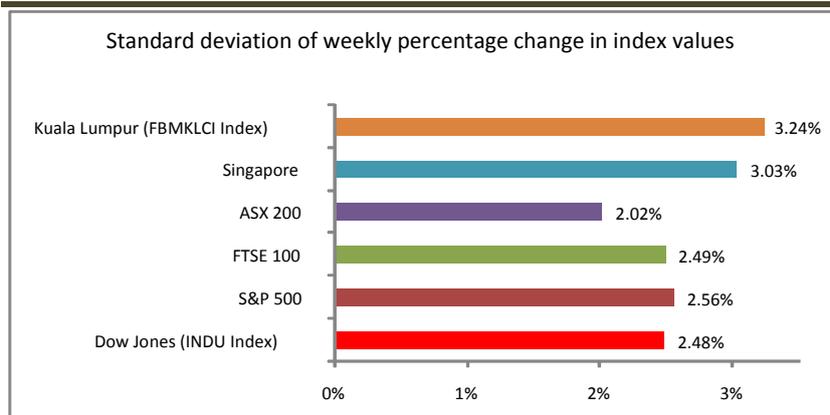
⁷ Dr Martin Lally, an advisor to the New Zealand regulator recently stated that the MRP has increased as a consequence of the GFC.

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Establishment Return Requirement (WACC)

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Fig: Volatility of stock market indices



Based on the current analysis of KLSE market return of 8.8%, the ST's draft recommendation for MRP is 4.8% for the first Regulatory Term. The ST will review its analysis on MRP and determine a final estimate at least two months prior to the commencement of the first Regulatory Term.

5. Specific WACC estimates for the SESB business entities

The ST will set the same WACC for all the SESB business entities. The ST does recognise that the regulatory risk is slightly different for an entity operating under a Price Cap regulatory framework as compared to a Revenue Cap regulatory arrangement. However, this difference is small (and difficult to quantify, given the inherent error in parameter estimation) and mitigated by the ability of Customer Services to adjust its capital expenditure program with sales variations.

The ST's position is consistent with international regulatory precedence. For example,

- the AER sets the same WACC parameters for both Price Cap and Revenue Cap regulated entities; and
- Ofgem and EMA also adopt the same WACC parameters across all regulated entities (Transmission and Distribution. EMA applies the same WACC for setting regulated vesting contracts for determining generation tariff).

6. Process and timeframe for estimating WACC

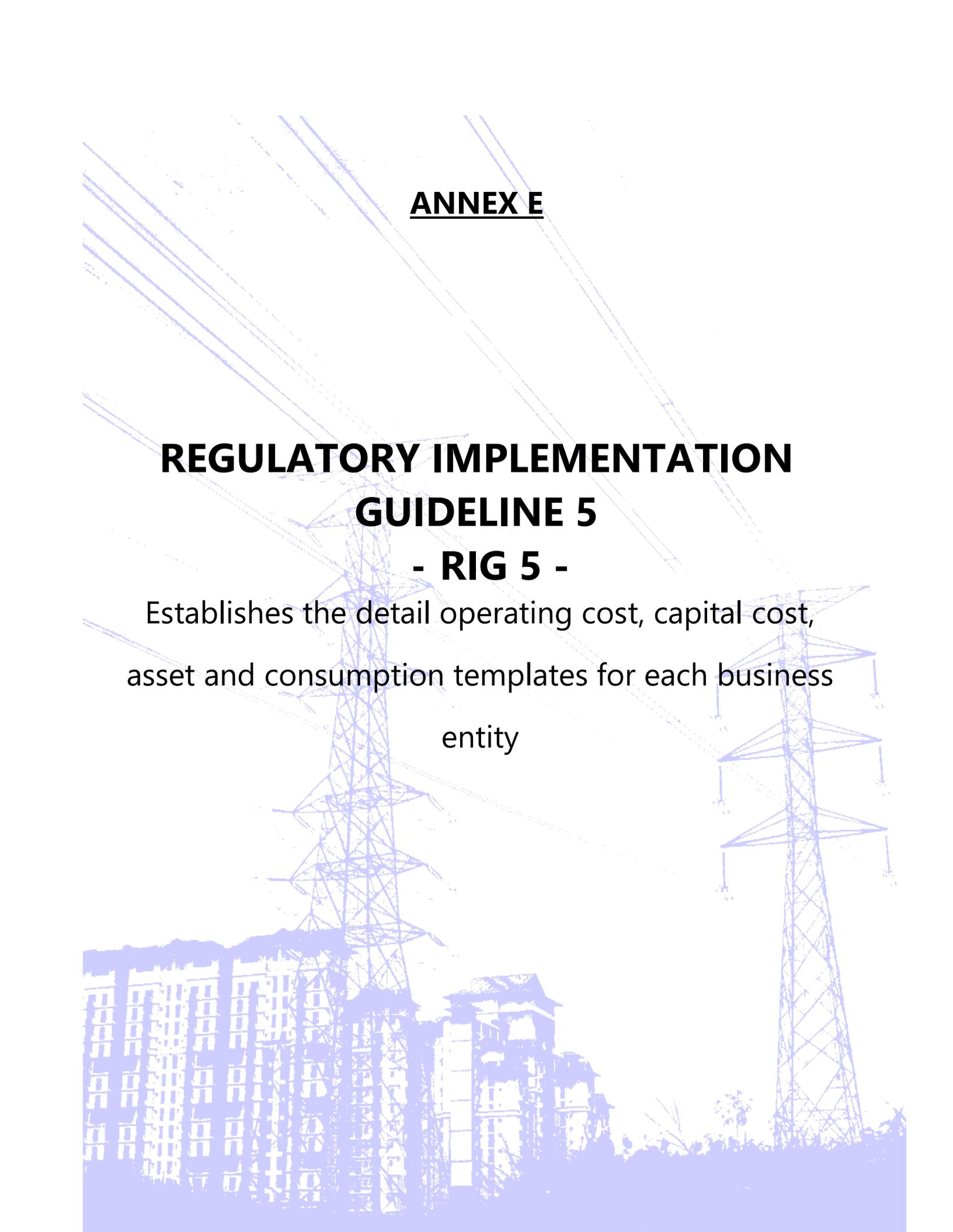
In setting the regulatory WACC, the ST will adhere to the following process:

- SESB to present its WACC estimate based on the principles outlined in RIG 4 nine months before the commencement of the Regulatory Term.

- The ST will present its draft determination within one month of receiving SESB’s proposal. The ST will allow SESB one month to respond to its draft determination.
- The ST will present its final determination on regulatory WACC at least six months before the start of the first Regulatory Term.

In summary, the ST will adopt the following principles for setting regulatory WACC for the first Regulatory Term.

WACC parameter	Key principles	Parameter value
Risk free rate (Rf)	10 to 120 year yield on MGS	Parameter value based on 5 year historical average at the commencement of the First Regulatory Term (adjustments for exceptional market events, like the GFC).
Debt margin(Dm)	Credit rating of BBB+ (S&P estimate) or AA (RAM estimate) Debt portfolio based on 10 year term to maturity.	Based on 5 year historical average (adjustments for exceptional market events, like the GFC).
Gearing (G)	Consistence with maintaining investment grade credit rating (BBB+, S&P estimate or AA, RAM estimate).	Draft determination of 55%.
Equity beta (Be)	Market analysis and Benchmarking. Consistent with gearing assumption.	Initial estimate of 1.46. Final determination based on updated market analysis and benchmarking.
Market Risk Premium (MRP)	Benchmarking with other markets. Relevant international regulatory benchmarks.	Draft Determination of 4.8%

The background of the slide features a large, blue-tinted image of a high-voltage power transmission tower. The tower is a lattice structure with multiple cross-arms supporting power lines. In the lower-left corner, there is a smaller, semi-transparent image of a multi-story building with a grid-like facade. The overall background is a light blue gradient.

ANNEX E

**REGULATORY IMPLEMENTATION
GUIDELINE 5
- RIG 5 -**

Establishes the detail operating cost, capital cost,
asset and consumption templates for each business
entity

1. Objective

The objective of RIG 5 is to establish detailed operating cost, capital cost, asset and consumption templates for the SESB business entities.

2. Managed Market Model

In the Managed Market Model, SESB's business is categorised into five business entities, which are SESB Generation which include grid and non-grid plants, Single Buyer, Transmission, System Operator and Customer Services. These business entities are defined below:

- **Single Buyer:** The main function of the Single Buyer is to procure electricity from IPPs and SESB Generation based on the terms of the PPAs entered into between SESB and the IPPs and SLAs entered into between SESB Planning Division and SESB Generation. The Single Buyer shall develop dispatch schedules based on least cost scheduling methodology for SESB's generation and the IPPs plants. The least cost scheduling methodology is based on the fuel costs (heat rate and fuel price) and variable operating costs of all the generation plants available for all IPPs and SESB generation plants. The Single Buyer produces the day-ahead scheduling.
- **SESB Generation:** This business entity includes the ownership, management and operation of grid and non-grid generation plants owned by SESB. Single Buyer procures from SESB Generation for the sale of electricity based on SLAs for the following plants:
 - Patau-Patau Power Station;
 - Tenom Pangi Hydro Power Station;
 - Kubota Power Station; and
 - Additional plants (if necessary).

On SESB grid and non-grid plants which are recognised and identified as Non-SLAs plants, shall be dispatched based on the estimated heat rate, VOR, capacity charge and FOR to recover its respective operating costs and book value for the remaining life of the plant.

- **Transmission:** This business entity includes the management, maintenance and development of the SESB transmission system for the transmission of electricity to

RIG 5

Establishment of Operating Cost, Capital Cost, Asset and Consumption Templates

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end customers. Transmission system planning is done by the Transmission Planning, Planning Division for the usage of Transmission business entity.

- **System Operator:** This business entity includes the current functions of transmission system operations of SESB.
- **Customer Services:** This business entity includes the management, maintenance and development of the distribution system Non-SLAs and the sale of electricity to customers.

In addition to the five Business entities of SESB, the IPPs are collectively the sixth business entity, contracting with the Single Buyer for sale of electricity.

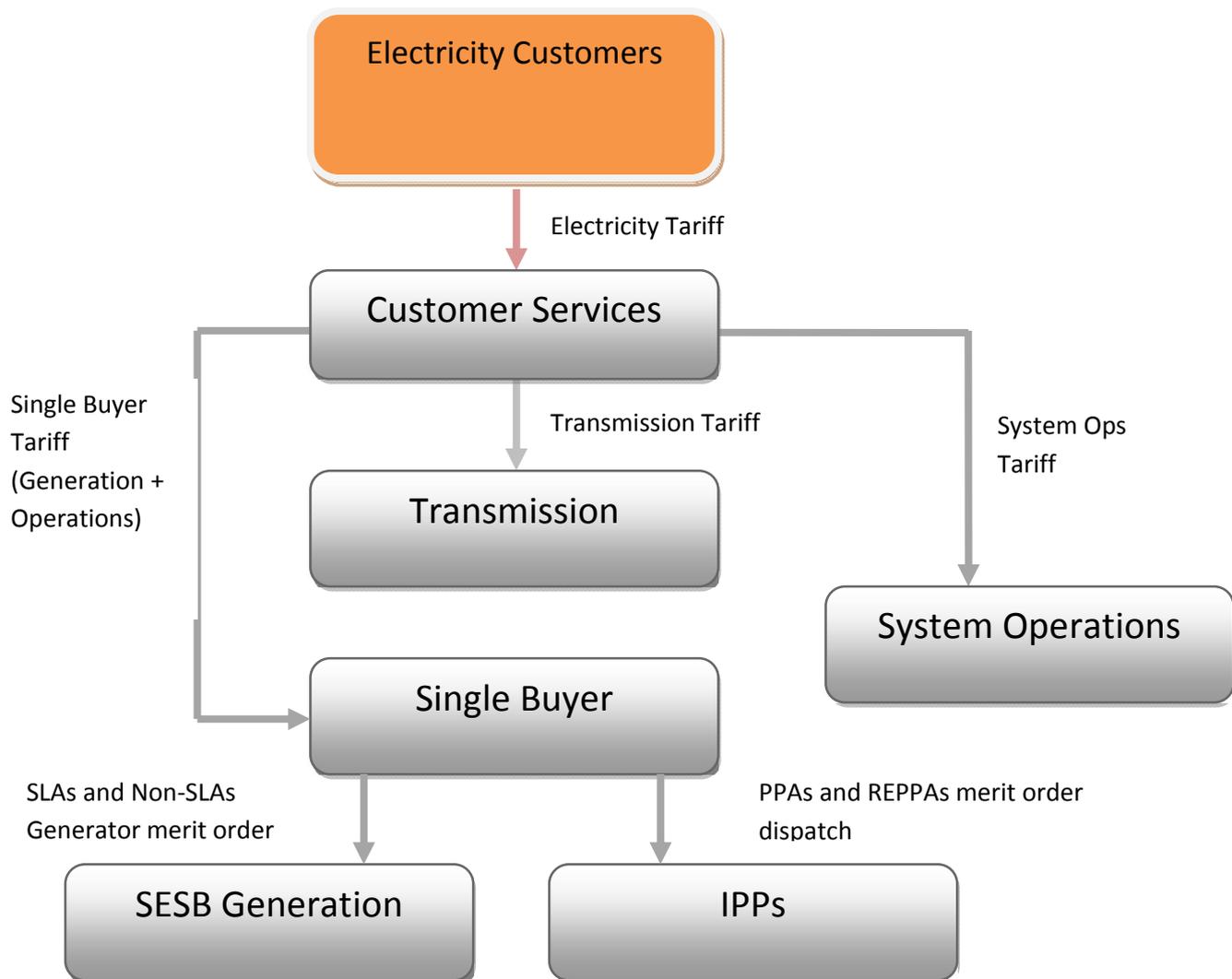
The Customer Services business entity charges electricity customers a tariff for the use of electricity. This tariff is a bundled tariff and incorporates a charge for all Generation (IPPs, SESB generation and cost of Single Buyer), Transmission, System Operations and Customer Services. Customer Services receives all the tariff revenue from electricity customers and subsequently used to cover the cost of Transmission and the System Operations business entity as its share of revenue based on Transmission Tariffs and tariff for System Operations.

The Single Buyer charges a Single Buyer Tariff to the Customer Services business entity, comprising a **Generation component** (based on forecasts costs of generation determined by the capacity payment and FOR in the PPAs, SLAs, Non-SLAs, REPPAs, and all variable generation costs based on the merit order dispatch) and an **Operations component** (based on the operating costs of managing the operations of the Single Buyer). The Single Buyer receives the Generation Revenue and pays SESB Generation and the IPPs.

The flow of funds between the five SESB business entities and the IPPs is shown below¹.

¹ Regulatory Implementation Guideline 2 (RIG 2) presents in detail the flow of funds between the business entities

FIG: Flow of funds for Managed Market Model



The five business entities of SESB Generation, Single Buyer, Transmission, System Operations and Customer Service will be ring fenced with separate accounts.

3. Data Requirement

The tariff setting and regulatory framework for each of the SESB business entities are outlined in RIG 2 and RIG 3.

The ST requires SESB to provide the following data in the prescribed format to enable the implementation of the regulatory and tariff setting framework (as per RIG 2 and RIG 3) for each of the business entities.

The ST presents an indicative format for costs to be segmented into various cost categories. SESB is required to ensure that costs are presented in sufficient detail and that cost categories reflect broad cost functions. It is also imperative that actual cost data is able to be recorded and presented by the forecast cost categories.

SESB is required to provide feedback on the suggested cost categories for each of the business entities within 15 days of receiving this document. The feedback should outline clearly what cost categories SESB is proposing for each of the business entities. The ST will consult with SESB before finalising the cost categories.

The ST's indicative cost categories for each business entity are present below and are meant to provide a template for SESB to work with and finalise the cost categories.

4. Single Buyer

The aim is to collect data for the operations of the Single Buyer, the energy purchases from the IPPs and SESB Generation.

4.1. Operations of Single Buyer

The operations of the Single Buyer should include all operating and capital costs required to effectively and efficiently manage all the functions of the Single Buyer to procure electricity from the IPPs and SESB Generation (Prescribed Services).

In relation to fuel procurement process and contracts made, SESB will be required to demonstrate that its processes and the contracts entered into are consistent with principles of economic efficiency (particularly in relation to MFO and distillate). The Single Buyer Rules will set out the detailed requirements in relation to ensuring that electricity prices only reflect efficient procurement costs. The format for operating cost and capital cost inputs (and forecast data) is presented in Appendix 1 (Worksheets: Asset inputs and Opex inputs & allocations).

4.2. Single Buyer purchases from IPPs

This cost category includes all costs incurred by the Single Buyer to purchase electricity from the IPPs based on the terms and conditions of the PPAs and the Managed Market Rules². The format for capturing all data, including dispatch, heat rates, fuel costs, capacity payments and variable and fixed O&M is presented in Appendix 1 (Worksheet: Single Buyer Generation inputs).

4.3. Single Buyer purchases from SESB Generation

This cost category includes all costs incurred by the Single Buyer to purchase electricity from the SESB Generators based on the terms and conditions of the Service Level Agreements (SLAs) and the Managed Market Rules. For non-SLAs generators, the cost will also be classified as capacity payment (derived to recover the opening book value of the asset at WACC and asset's average life) and variable and fixed O&M (to recover the estimated maintenance cost of the non-SLAs generation asset). The format for capturing all data (PPAs, SLAs and non-SLAs) including dispatch, heat rates, fuel costs, capacity payments and variable and fixed O&M is presented in Appendix 1 (Worksheet: Single Buyer Generation inputs). In addition, we recommend SESB provides asset information on each of the SESB generation companies such that we can ensure that the capacity payment delivers an acceptable return. This is because each SESB Generator is a separate company wholly owned by SESB and therefore distortions may be present in the capacity charge (the capacity charges may deliver a return in excess or below the required WACC).

Appendix 1 (Worksheet: SESB Generation inputs) provides a suggested format for all the asset base inputs for SESB Generation. The asset base inputs include asset categories, remaining life, useful life and capital expenditure forecasts for the Regulatory Term. The SESB Generation inputs worksheet in Appendix 1 also incorporates the tax written down values of SESB Generation, capital allowances and capital allowance rates.

4.4. Demand

Appendix 1 (Worksheet: Demand & summary gen costs) provides a summary of the dispatch and cost information contained in the Single Buyer Generation inputs worksheet, and also includes an overall demand input section (with an adjustment for expected losses). The overall demand should match the summary of the dispatch information from SESB Generation and the IPPs, less expected losses.

SESB should provide supporting documents to demonstrate the reasonableness its demand forecasts (as approved by latest JPPPET), such as historical figures and trends. Expected

² As mentioned in Regulatory Implementation Guideline 1. The Managed Market Rules need to be developed by the Single Buyer based on the principles outlined in the Grid Code.

losses should be supported with loss estimation studies. SESB should also provide details of its loss reduction strategy and forecast cost of achieving loss reductions. The ST will consider the opening loss levels, submissions from SESB and other stakeholders in its assessment of SESB's proposal.

5. Asset inputs for Transmission, System Operations, Single Buyer Operations and Customer Services

The indicative format for all the asset related inputs for the Transmission, System Operations, Single Buyer Operations and Customer Service business entities are presented in Appendix 1 (Worksheet: Asset inputs).

The asset base inputs include asset categories, closing historical asset values for the Base Year, remaining life, useful life and capital expenditure forecasts for the Regulatory Term. SESB is required to provide the asset categories which best represent its asset base and mix of plant and equipment. For example, Transmission asset categories should include at least transmission lines, sub stations, transformers, switchgear and transmission towers. For Customer Services, asset inputs are divided between retail operations and distribution, for which the asset categories should include at least poles, cable and lines, transformers, substations and meters.

The high-level asset inputs in Appendix 1 should also be accompanied by supporting documents which provide a detailed breakdown of assets (for example, list of buildings, plant etc), additions and retirements (if any).

Appendix 1 also incorporates all tax inputs and inputs on any upfront customer contributions or government grants. Asset categories for tax purposes may be less disaggregated if capital allowance rates do not vary between major asset categories.

6. Operating cost inputs for Transmission, System Operations, Single Buyer Operations and Customer Services

The indicative format for all the operating cost inputs for the Transmission, System Operations, Single Buyer Operations and Customer Service business entities are presented in Appendix 1 (Worksheet: Opex inputs & allocations).

SESB is required to provide the operating cost categories which best represent the business of Transmission, System Operations, Single Buyer Operations and Customer Services. For

example, Transmission operating cost categories should include at least staff costs, planned and unplanned maintenance, administration.

For Customer Services, operating cost inputs are divided between retail operations and distribution network, for which the operating cost categories should include at least staff costs, planned and unplanned maintenance, meter reading, billing, call centre (customer operations). Customer Services operating costs input should also include the interest payments on customer deposits.

7. Joint costs

Joint costs are those costs which are common to all (or at least two) SESB business entities. Joint costs will be separately identified and captured and allocated to the SESB business entities. Examples of joint costs include centralised head office functions like corporate finance, human resources, information technology, legal and other administrative services. Joint costs will be allocated to the business entities based on a cost allocation methodology (primarily based on causal principles). Joint costs may also include assets which are used by more than one business entity, such as the head office building, etc.

The indicative format for joint costs is presented in Appendix 1 (Worksheet: Joint cost inputs). SESB is requested to review the template and provide suitable cost categories.

7.1 Joint cost allocations

As set out in RIG 7, joint costs incurred by the SESB business entities must be allocated between the relevant business entities on the basis of an approved cost allocation methodology. Appendix 1 (Worksheet: Opex input & cost allocations) includes a cost allocation matrix that specifies the allocation of the joint cost inputs between the Transmission, System Operations, Single Buyer Operations and Customer Services entities.

8. Regulatory reporting

While designing and finalising these data templates, SESB must ensure that it is able to report actual cost data (both asset and operating costs) in exactly the same format as the finalised data templates.

RIG 5

Establishment of Operating Cost, Capital Cost, Asset and Consumption Templates

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9. Process of finalisation

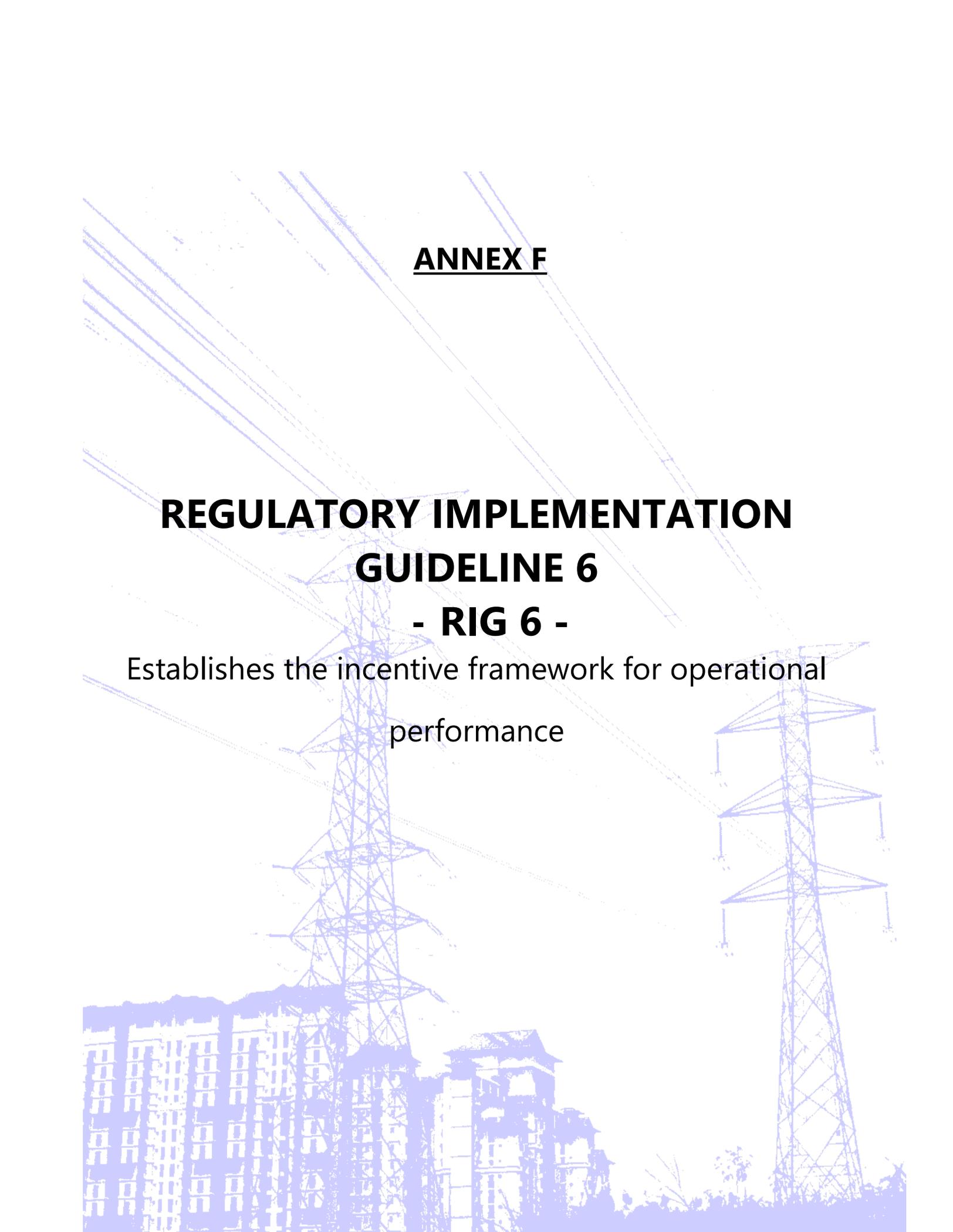
The ST will expect SESB's draft response on the data templates 15 working days after it has received RIG. The ST will review the draft data templates as proposed by SESB and issue a draft recommendation within 5 working days for final consultation with SESB.

10. Appendix 1

Appendix 1 is an Excel model and incorporates the following worksheets:

Worksheet	Description
Single Buyer Generation inputs	Data inputs on IPPs, SESB generation. Costs based on IPPs and SLAs and non-SLAs. Objective is to calculate all costs of generation (including fuel) which the Single Buyer incurs in procuring electricity.
Demand and summary generation costs	Total demand inputs, including expected losses. Also includes a summary of the generation costs from the Single Buyer Generation inputs sheet.
SESB Generation inputs	Asset base inputs for SESB Generators. The objective is to check if the capacity payments in the SLAs deliver an appropriate return to the respective generators.
Asset inputs	Asset base inputs for Transmission, System Operations, Single Buyer Operations and Customer Services. The objective is to calculate return on asset, return of asset and tax payments in the revenue requirement model.
Opex inputs and allocations	Operating cost inputs for Transmission, System Operations, Single Buyer Operations and Customer Services. Also includes the cost allocation matrix for the allocation of joint costs. The objective is to forecast recovery of efficient operating costs in the revenue requirement model.
Joint cost inputs	This worksheet captures all assets and operating costs which are common to more than one SESB business entity. These joint costs will be allocated to the various SESB business entities based on the cost allocation principles enshrined in RIG 7.

Appendix 1 is part of RIG 5. RIG 5 should be read and analysed in conjunction with Appendix 1.

The background of the page features a blue-tinted image of high-voltage power lines and towers stretching across the sky, with a cityscape visible at the bottom. The text is overlaid on this image.

ANNEX F

REGULATORY IMPLEMENTATION GUIDELINE 6

- RIG 6 -

Establishes the incentive framework for operational
performance

1. Objective

The objective of RIG 6 is to provide guidelines to establish an incentive framework for operational performance for the SESB business entities.

2. Background

The ST has recommended a regulatory framework to determine efficient revenues which the SESB Business entities are able to recover from electricity customers. This regulatory framework is outlined in detail in RIG 2, RIG 3 and RIG 4. In summary the regulatory framework incentivises the SESB business entities to strive for efficiencies in operating and capital expenditures, as business entities retain efficiencies achieved during the current Regulatory Term and carry-forward some operating cost efficiencies to the subsequent Regulatory Term. In addition the regulatory framework places strong incentives to pursue financial efficiencies as the regulated WACC is set based on efficient benchmarks and business entities are able to retain any benefit of lowering their cost of capital below the set regulated WACC.

The ST considers it prudent and indeed part of its overall design of a holistic incentive-based regulatory system to set standards and incentives to improve operating performance. This is because the ST does not want cost and financial efficiencies to be achieved at the expense of lowering operational performance.

The ST considers that operational performance primarily consists of network performance and customer service. Therefore the ST will consider establishing standards, benchmarks and incentives (and disincentives) for network performance and customer service (where relevant) for the SESB business entities. As part of RIG 6, the ST will establish the process and guidelines on how it plans to implement the incentive framework for operational performance.

This incentive scheme will work in conjunction with and will not replace all other performance and customer service standards set for SESB (such as meeting set appointment times etc) and any guaranteed minimum service level standards.

3. Finalising operating performance indicators

The first step in designing the incentive scheme for operational performance is to set relevant operating performance indicators for the SESB business entities. This is the most important step in the overall design of the scheme. The ST proposes to adopt the following criteria in setting the operational performance indicators:

- relates closely to the business activities of the SESB business entities;
- highly valued by electricity customers;
- can be objectively measured; and
- can be independently audited.

The ST proposes that each of the SESB business entities recommend a list of 3 operational performance indicators which are not self-regulated such as performances related to PPA compliance and demonstrate that they comply with the criteria as outlined above. For example, the ST notes that:

- system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) are commonly used performance indicators by electricity distribution businesses in Peninsular Malaysia (TNB), Australia, UK and New Zealand and restoration time and power supply interruption events are adopted in Singapore. Call centre performance and losses have been adopted recently by regulators in Australia and UK.
- circuit and plant availability, supply interruption and losses are common indicators adopted for the electricity transmission businesses in Australia, UK and Singapore. In addition power quality indicators (voltage dip incidents) have been used in Singapore for electricity transmission.
- market and system rule compliance and demonstration of efficiency and transparency are key performance indicators adopted for independent system operators and market companies. These may be relevant for the Single Buyer and Transmission System Operator.

The ST recommends that the SESB business entities take into consideration performance standards set in Peninsular Malaysia and other international jurisdictions which have implemented incentive-based regulatory frameworks for electricity industries. In addition, the ST would expect Customer Services to establish performance indicators relevant for both small and large customers.

4. Setting targets

In setting future targets, the ST will take into consideration, historical performance, the impact of the proposed capital and operational expenditure plans and the inherent variability in performance data.

The ST can either set a point estimate target for each performance indicator, or an upper bound and a lower bound target for each performance indicator. In the first model, actual performance will be compared to the point estimate target to derive either an incentive or penalty. In the second model, a penalty is applicable if actual performance is less than the lower bound target, an incentive is applicable if actual performance is above the upper bound target and no penalty or incentive is applicable if actual performance lies between the lower and upper bound targets.

The ST's draft recommendation is to adopt the second model, which sets a lower and upper bound performance target. The ST will review at least 3 years of historical data in setting both the lower bound and upper bound performance targets.

5. Incentive scheme

The ST proposes to link the electricity tariffs customers pay to the level of performance expected to be delivered by the respective SESB business entities. Therefore, if the SESB business entities exceed the upper bound performance targets, they should be allowed to charge higher prices. Alternatively, if any of the SESB business entities performance falls below the lower bound performance target they should charge lower prices to customers reflecting a lower grade of service.

Finally, the ST proposes to set a cap on the maximum penalty or incentive for the SESB business entities. Therefore in addition to setting lower and upper bound values for each parameter, the ST will need to set targets for upper bound cap and lower bound cap for each performance indicator.

The ST notes that the AER¹ has capped both the incentive and penalty for Victorian electricity distribution businesses at 5% of total distribution revenues and about 2% of total transmission revenues for the Victorian electricity transmission business. Similarly Ofgem² has capped both the incentive and penalty at about 97 bps of Return on Regulatory Equity (RORE) for distribution businesses to manage an efficient level of network losses and 42 bps

¹ AER, Final decision SP AusNet transmission determination, January 2008, page 185. AER, Final decision, Victorian electricity distribution network service providers, Distribution determination 2011–2015, October 2010, page 739

² Ofgem, Electricity Distribution Price Control Review, Final Proposals, 7 December 2009, page 16, 17

RIG 6

Establish Incentive Framework for Operational Performance

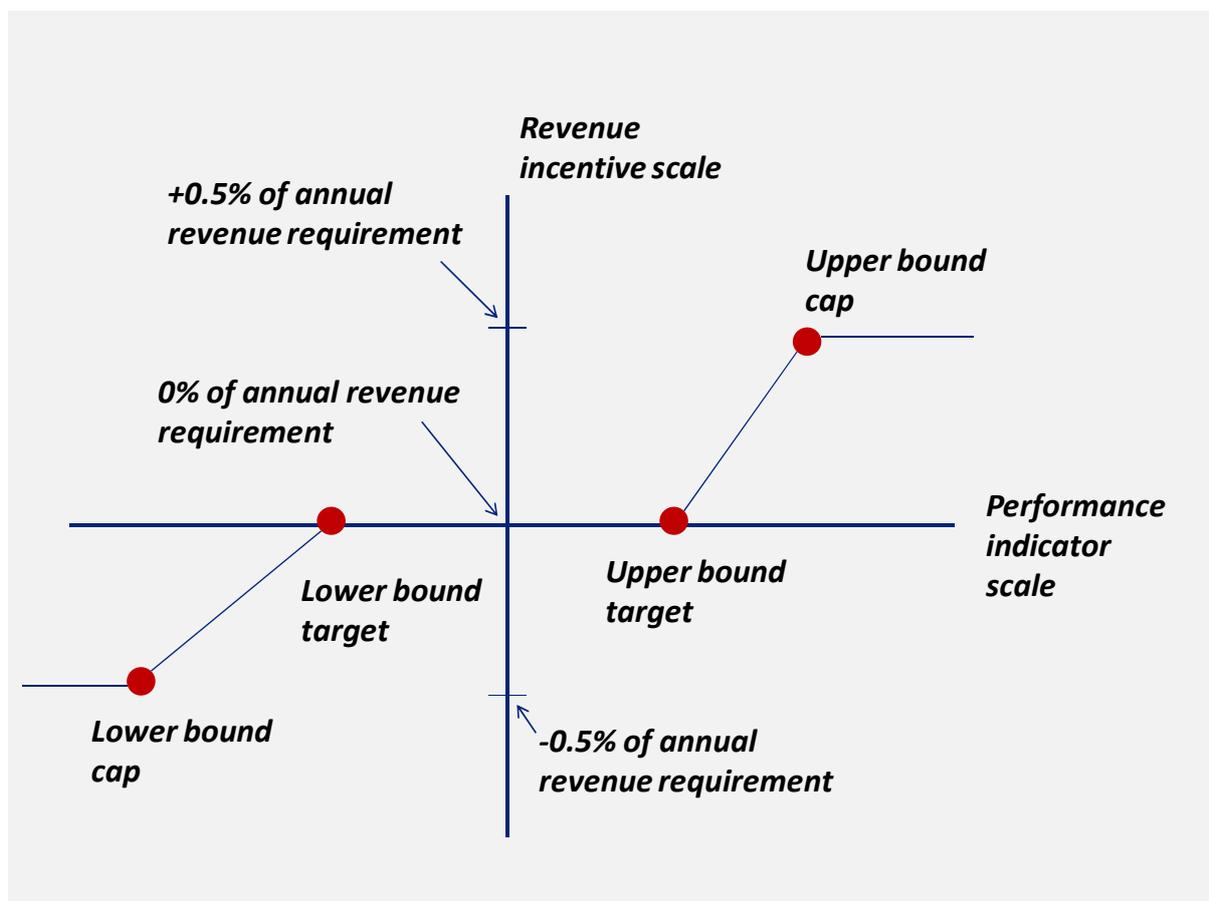
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of RORE for several customer satisfaction indicators. Presently in Peninsular Malaysia, the ST has adopted a capped of 0.5% of annual revenue requirement for both the incentive and penalty for TNB's businesses entities.

The ST proposes to cap the annual financial exposure to the SESB business entities at 0.5% of annual revenue requirement for the first Regulatory Term as determined in accordance with RIG 3. In determining this cap, the ST has taken into consideration that incentive regulation is relatively new in Malaysia and therefore a soft start is recommended. As the ST and the SESB business entities get more experience with implementing incentive-based regulation, the cap can be increased and be gradually brought in line with international benchmarks.

The proposed incentive scheme is illustrated below.

FIG: Proposed incentive scheme



As shown above, if actual performance is within the Upper and Lower bound targets, there is no incentive or penalty. If actual performance is below the Lower bound target, the penalty starts and caps out at 0.5% of annual revenue requirement when actual

performance reaches (and exceeds) the Lower bound cap value. Conversely, if actual performance is better than the upper bound target value, the incentive commences and caps out at 0.5% of annual revenue requirement when actual performance reaches or exceeds the Upper bound cap value.

The revenue incentive or penalty amounts for actual performance between the upper and lower bound target values and their respective cap values will be based on a straight line linear equation.

A worked example is provided below for illustration. Consider the following operational performance scheme, which comprises of SAIDI and SAIFI targets with annual revenue requirement of RM 100 million and total incentive cap of 0.5% of revenue requirement.

FIG: Incentive scheme worked example

	SAIDI (in minutes)	SAIFI
Upper bound cap	5	1.5
Upper bound target	10	2
Lower bound target	15	2.5
Lower bound cap	20	3
Actual performance	7	1.6

SAIDI incentive 0.15% * 100 = RM 0.15 million.

Where, 0.15% is calculated based on slope equation³ with SAIDI upper bound cap representing 0.25% revenue incentive and SAIDI upper bound target representing 0% revenue incentive.

$$Y = -0.005 * X + 0.005$$

X = Actual SAIDI of 7

SAIFI incentive 0.20% * 100 = RM 0.20 million.

Where, 0.20% is calculated based on slope equation with SAIFI upper bound cap representing 0.25% revenue incentive and SAIFI upper bound target representing 0% revenue incentive.

$$Y = -0.05 * X + 0.01$$

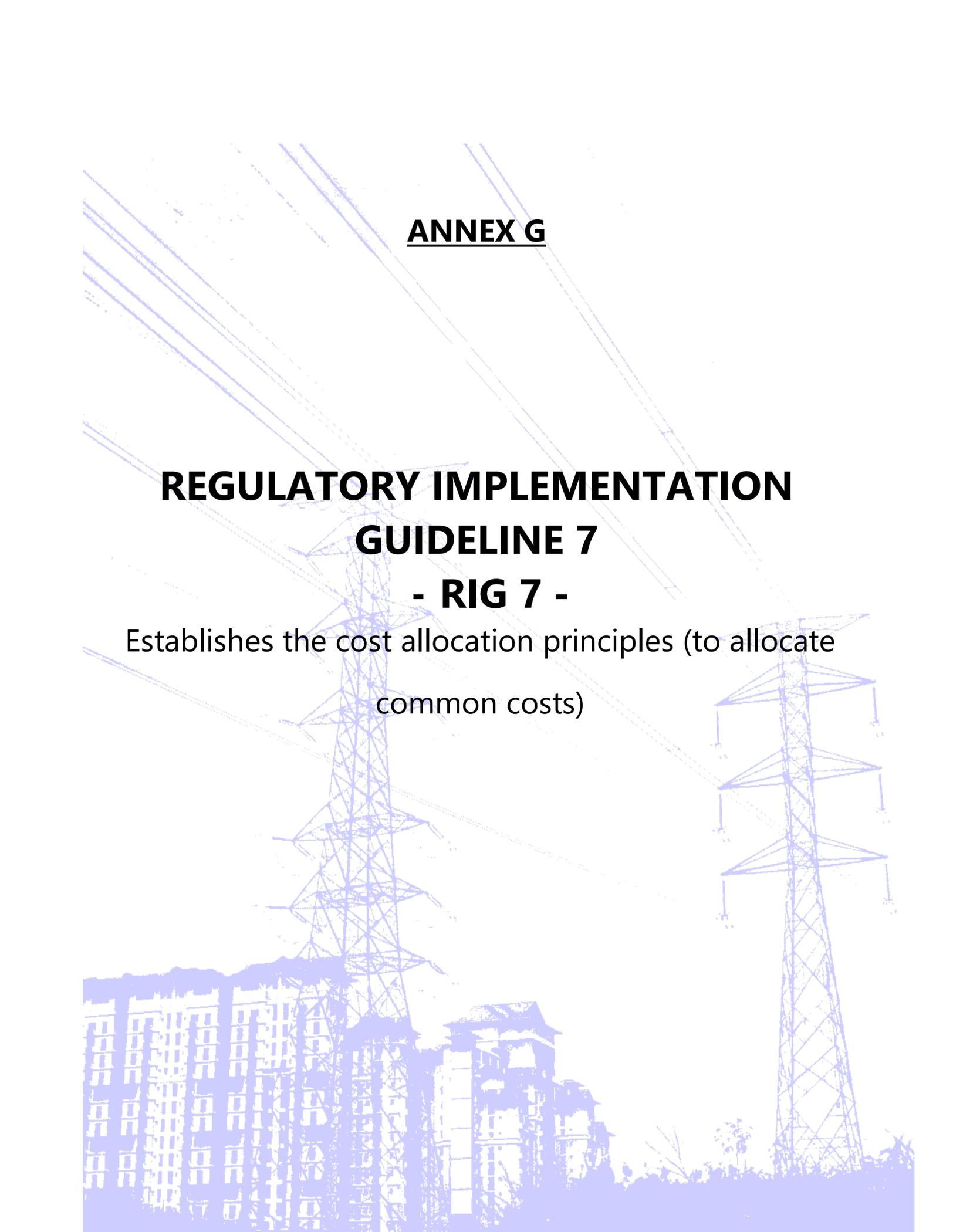
X = Actual SAIFI of 1.6

³ The slope equations are based on straight linear regression. The slope equation will vary with upper / lower bound cap and upper / lower bound values.

6. Implementation process

The ST proposes the following implementation plan.

- The SESB business entities propose a draft set of 3 performance indicators along with the lower bound, upper bound and their respective cap values within 2 months of the finalisation of RIG 6, which best meet the criteria specified in section 3 of RIG 6. Included in the SESB business entities proposal will be at least 3 years of historical data and the basis and process of calculating the parameter values. The ST will review the proposal of the SESB business entities and provide its draft determination within 2 months. The ST will then consult with the SESB business entities and other stakeholders as required and finalise the 3 performance indicators within 1 month from the date of issuance of its draft determination.
- The ST will not adjust electricity tariffs annually during the first regulatory period. Instead, the ST recommends that the incentive or penalty amounts be calculated for every year and the accumulated total for the first Regulatory Term be amortised and included as part of revenue requirement over the subsequent Regulatory Term. This will ensure that electricity tariffs are not impacted for the first Regulatory Term while still retaining the incentive to improve and maintain operational performance. The ST will consider doing annual adjustments to electricity tariffs within a Regulatory Term later.
- For the first regulatory period, no incentive or penalty amounts will be implemented as practice in Peninsular Malaysia, UK and Australia when the IBR regime started. Once the ST gets more experience in administering the scheme and setting targets it will consider implementing the incentive or penalty scheme in the subsequent regulatory period.



ANNEX G

**REGULATORY IMPLEMENTATION
GUIDELINE 7**

- RIG 7 -

Establishes the cost allocation principles (to allocate
common costs)

1. Objective

The objective of RIG 7 is to provide guidelines to establish cost allocation principles for allocating joint costs incurred by SESB in supplying electricity to customers in Sabah & Wilayah Persekutuan Labuan between the various SESB business entities.

2. Background

The costs that a regulated entity incurs in the provision of regulated services can be broadly categorised into either direct costs or joint costs.

2.1 Direct costs

Direct costs are costs incurred by a regulated entity for business activities that are required solely for providing regulated services applicable for that specific regulated entity. Direct costs incurred by the relevant regulated entity are ring fenced from other activities of the corporate group that the regulated entity belong to and are recorded and captured directly in an account category which belongs solely to the relevant regulated entity.

For example, costs incurred for meter reading activities typically are direct costs for a regulated distribution business entity and are recorded and captured directly in the ring fenced accounts which belong solely to that relevant regulated entity.

2.2 Joint costs

Joint costs are costs which relate to certain business activities that are performed centrally by the corporate group for more than one regulated entity or a combination of regulated and non-regulated business entities. Centralisation of certain corporate functions such as corporate IT and Treasury makes business sense as these functions are common to all business entities (both regulated and non-regulated) of the corporate group and therefore centralisation of the function is often the most efficient business delivery model.

These joint costs have to be allocated to the relevant regulated business entities to enable regulated cost recovery from electricity customers via regulated electricity tariffs. Before the joint cost allocation process, the regulated entity must demonstrate that these joint costs are incurred to provide regulated services and therefore need to be recovered through regulated tariffs. Once that is established, robust joint cost allocation rules need to be developed to ensure that the costs allocated to regulated entities are efficient and recoverable through regulated pricing.

RIG 7

Establish Cost Allocation Principles

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RIG 7 presents the principles that the ST has established for SESB to follow in allocating joint costs to its various regulated business entities. For clarification, costs as implied in this guideline include both operating costs and capital expenditure.

3. Key principles for allocating joint costs

The ST has established the following key principles for developing a robust cost allocation methodology to allocate joint costs.

- Only those joint costs are to be allocated to regulated business entities which are incurred in the provision of regulated services for the respective regulated entities.
- Only efficient joint costs will be allocated to regulated entities.
- A particular joint cost can only be allocated once.
- The regulated entity must clearly specify how joint costs are allocated and the basis for allocation (cost allocation methodology).
- The sum of allocated joint costs must not exceed the total value of the joint costs.
- The basis of allocating joint costs, once approved by the ST must be reflected in the preparation of the regulatory accounts and must not be changed during the course of the Regulatory Term.

4. Implementation

This section outlines the ST's preferred approach on the implementation of the allocation of joint costs based on the principles as specified in Section 3 of this guideline.

4.1 Cost allocation methodology

The ST will expect the relevant SESB business entities to propose a detailed cost allocation methodology, consistent with the cost allocation principles. The cost allocation methodology should incorporate at least the following items:

- A clear presentation of SESB cost structure, with a complete listing of both regulated and non regulated business entities.
- A clear explanation of all joint costs and justification on how these costs are relevant to the provision of electricity to customers connected to the SESB electricity network in Sabah & Wilayah Persekutuan Labuan.
- Detailed justification of the basis adopted to allocate joint costs to the various business entities. The ST expects that a causal basis be adopted to allocate most joint costs. If a

causal basis to allocate joint costs is not applicable, then the rationale for departure from a causal basis must be clearly explained.

- Demonstration that the sum of all allocated costs is not greater than the total joint costs.
- A clear explanation on how the proposed joint cost allocation will be implemented in the financial and management accounting systems. The business entities must be able to allocate actual joint costs incurred based on the proposed cost allocation methodology in an efficient and timely manner.
- The ST will review and approve the cost allocation methodology within 2 months of receiving the cost allocation methodology.
- The cost allocation methodology, once approved will not change during the Regulatory Term.
- Any changes to the approved cost allocation methodology for subsequent Regulatory Terms must be approved by the ST.

4.2 Regulatory accounts

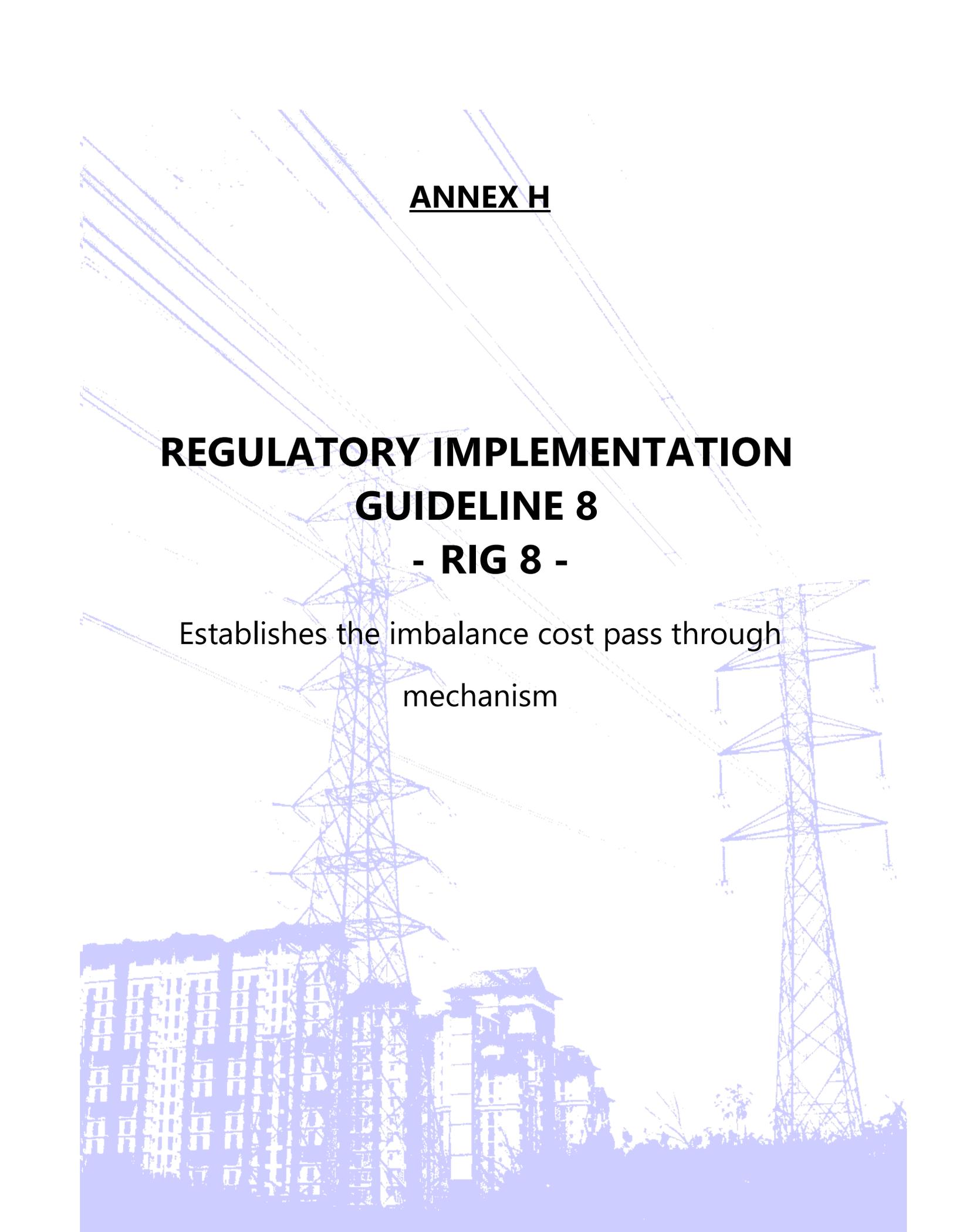
The ST will expect the Regulatory Accounts for the SESB business entities to be based on the approved cost allocation methodology. The ST will require the following:

- A statement from the auditors of the SESB business entities confirming that the regulatory accounts are consistent with the approved cost allocation methodology.
- Any inconsistencies found by the auditors between the proposed regulatory accounts and the cost allocation methodology must be highlighted along with the reasons for non-compliance signed off by senior management of the SESB business entities.

In conducting the audit of the regulatory accounts, the ST does not expect the auditors to comment on the cost allocation basis which underpins the approved cost allocation methodology. The auditors are to focus only on compliance with the cost allocation methodology.

4.3 Forecasts

As per RIG 3, the ST will determine annual revenue requirement for each of the SESB business entities based on efficient forecasts of costs. Therefore, in determining the revenue requirement, the ST will ensure that forecasts of joint costs are allocated based on the approved cost allocation methodology.



ANNEX H

**REGULATORY IMPLEMENTATION
GUIDELINE 8
- RIG 8 -**

Establishes the imbalance cost pass through
mechanism

1. Objective

The objective of RIG 8 is to provide guidelines to establish an Imbalance Cost Pass-Through mechanism to enable the recovery of actual fuel related and other generation specific costs.

2. Background

The Single Buyer procures the required electricity generation (to meet customer demand) from IPPs and SESB generation. The procurement from IPPs are based on Power Purchase Agreements (PPAs) while SESB Generation are based on Service Level Agreements (SLAs) and Assets Recovery of Non-SLA generators. This Managed Market Model is specified in RIG 1. The Single Buyer charges a Single Buyer Tariff based on forecasts of electricity generation costs and all other operating costs which it incurs for the Regulatory Term. The Single Buyer Tariff comprises of two elements:

- **the Single Buyer Generation tariff component**, which is based on all costs of generation including fuel, capacity payments and other costs associated with the terms and conditions of the PPAs, SLAs, Non-SLAs and REPPA; and
- **the Single Buyer Operations tariff component**, which is based on the other operational and capital related costs of running the Single Buyer operations and includes an allocation of joint costs (if any).

For the generation specific tariff component, the Single Buyer operates under an Actual Cost regime as specified under RIG 2. The Actual Cost regime implies that the Single Buyer is able to recover its actual costs of procuring electricity from the IPPs and SESB Generation from electricity customers. The actual cost of procuring electricity from the IPPs and SESB Generation comprises:

- all costs incurred by the Single Buyer under the PPAs, the SLAs and the Non-SLAs such as capacity payments, fuel costs, incentive or bonus payments etc; and
- all costs incurred for the procurement of fuel oil and gas under various fuel oil and gas supply contracts by the IPPs and SESB with its fuel supplier.

As per RIG 2, the actual revenue earned by the Single Buyer based on the generation specific tariff component of its total Single Buyer Tariff is compared to the actual cost of electricity procurement for every six month period and variances (including the time value of money) adjusted for in subsequent six (6) month periods.

The actual cost incurred for the procurement of electricity generation by the Single Buyer will be different to its actual revenue received from the generation specific component of the Single Buyer Tariff, as it is based on forecasts costs which will be different to actual cost due to:

RIG 8

Establish Imbalance Cost Pass-Through Mechanism

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- variances between actual customer demand and forecast demand;
- variances between actual fuel oil prices and forecast prices;
- variances between forecast plant mix and actual dispatch; and
- variances between actual payments (and receipts from liquidated damages and withholding of capacity payments etc) from other terms and conditions of the various contracts, including the PPAs, SLAs and fuel procurement contracts from those included in the forecasts.

Every 6 months, commencing the start of the first regulatory term, the Single Buyer will compare its actual cost of electricity procurement to the actual revenue it receives based on the generation specific component of the Single Buyer Tariff. Any variances, either positive or negative, will be passed on to electricity customers via an adjustment in their final electricity tariffs. This tariff adjustment process is termed the Imbalance Cost Pass-Through Mechanism (ICPT) mechanism and is outlined below.

3. Implementation

This section outlines the ST's preferred approach on the implementation of the Imbalance Cost Pass-Through Mechanism. The key steps as outlined below include the 6 monthly adjustments for gas and fuel oil prices, preparation of a six monthly fuel cost report and the proposed tariff approval process.

In summary there are two adjustments as part of the ICPT Mechanism.

- The first is to adjust for the impact of any known changes in gas and fuel oil prices, the Fuel Price Adjustment.
- The second is an overall adjustment, The Fuel Cost Adjustment and Other Generation Specific Cost Adjustment which ensures that the Single Buyer's actual revenue based on its generation specific tariff component equals its actual cost of generation procured from SESB generation and IPPs

3.1 Fuel Price Adjustment

As outlined in RIG 3, the Single Buyer in forecasting its generation costs will use the current price of gas and fuel oil. Therefore changes to gas and fuel oil prices will impact the profitability (and viability) of the Single Buyer if corresponding changes are not incorporated in the generation specific tariff.

The ST will expect the Single Buyer to submit a detailed fuel cost report for every six month period of the Regulatory Term no later than 2 months before the expiry of the relevant six

month period based on actual 3 months and 3 months estimated actual. This fuel cost report will present the changes in fuel cost as a result of changes in fuel prices, unit sales and generation mix from the assume figures at the time the regulatory period and Base Tariff was established. The purpose of this report is to analyse the impact of all those changes to the total generation specific tariff component.

Changes in fuel price

The Single Buyer will present detailed analysis and documentation supporting and verifying the changes to both gas and fuel oil prices for the period. The documentation should include

- Government mandated changes to gas prices; and
- Pricing data for fuel oil consistent with current fuel oil contracts.

Adjustment Formula for Fuel Cost and Other Generation Specific Cost

The Single Buyer will present the impact of changes in gas and fuel oil prices and Other Generation Specific Cost on the generation specific tariff component. This adjustment will be based on (i) Fuel Price Adjustment Formula and, (ii) Other Generation Specific Cost Adjustment Formula. These formulas will determine the Generation Specific Tariff Component for the Single Buyer for the following 6 month period.

Fuel Price Adjustment formula

This formula is to capture the variation in fuel cost as a result of changes in the fuel price, generation mix, foreign exchange etc. from the figure used to establish Single Buyer Tariff.

FCPT	<i>FCPT 1 ± FCPT 2</i>
FCPT 1	$(EAFC - FFC)_{t-1} / EAUS_{t-1}$ <i>(Fuel cost Pass-Through for the period t-1 base on estimated actual fuel cost)</i>
EAFC	<i>Estimated Actual Fuel Cost based on 3 month actual and 3 month forecast</i>
FFC	<i>Initial Forecast of Fuel Cost based on assumed quantity and price at the beginning of Regulatory Period and Base Tariff is set.</i>
EAUS	<i>Estimated Actual Unit Sale</i>
FCPT 2	$(((FCPT_{t-1} * FUS_{t-1}) - AFC_{t-2}) / AUS_{t-2})$ <i>Adjustment for over or under recovery of actual fuel cost (Audited) for period t-2 and the Fuel Cost Pass-Through collected in period t-1.</i>
FUS	<i>Forecast Unit Sold</i>
AFC	<i>Audited Fuel Cost</i>
AUS	<i>Audited Unit Sold</i>

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Other Generation Specific Cost Adjustment formula

This formula is to capture the variation in Other Generation Specific Cost as a result of changes in, generation mix, foreign exchange etc., capacity payment, renewable energy, distillate cost etc from the figures assumed at the time the Single Buyer Tariff was established.

GSCPT	GSCPT 1 ± GSCPT 2
GSCPT 1	$(EAGSC - FGSC)_{t-1}/EAUS_{t-1}$ (Adjustment for variation in Other Generation Specific Cost)
EAGSC	Estimated Actual Other Generation Specific Cost base on 3 month actual and 3 month forecast
FGSC	Initial Forecast of Other Generation Specific Cost
EAUS	Estimated Actual Unit Sale
GSCPT 2	$(((GSCPT_{t-1} * FUS_{t-1}) - AGSC_{t-2}))/AUS_{t-2}$ Adjustment for under or over recovery of variation in Other Generation Specific Cost based on Audited and Estimated Actual figures
FUS	Forecast Unit Sold
AGFC	Audited Other Generation Specific Cost
AUS	Audited Unit Sold

Proposed tariff adjustment

The ST proposes that any adjustments to the Single Buyer generation tariff to account for any Fuel Cost Adjustment (FCPT 1) and Other Generation Specific Cost Adjustment (GSCPT 1) be implemented immediately in the following 6 month period based on actual 3 month and estimated 3 month figures. The ST will require the **Estimated Actual Fuel Cost and Generation Specific Cost report from Single Buyer** on the first week of month 4 of the relevant 6 month period. The ST will approve the FCPT 1 before the end of month 5 so that it can be implemented in the following 6 month period.

Any **over or under recovery** of Fuel Cost Adjustment (FCPT 2) and Generation Specific Cost Adjustment (GSCPT 2) from the audited actual figure will be adjusted accordingly in the subsequent 6 month period.

Audit requirement

The ST will require the Fuel Cost and Other Generation Specific Cost report and the application of the Fuel Price Adjustment and Other Generation Specific Cost Adjustment prepared by the Single Buyer to be certified as correct by a reputable audit company

whereby the cost of appointment of such audit company shall be part of the operational cost.

Worked example

The following worked example shows how changes to the gas commodity price and/or changes to the fuel oil commodity price will flow through to changes in the Fuel component and Generation Specific Tariff component of the Single Buyer. In the example:

- The initial Single Buyer Base Tariff is **24.61 sen/kWh**;
- In the first 6 month period of the Regulatory Year, the fuel cost has increased by **5.32 sen/kWh from 12.94 sen/kWh to 18.26 sen/kWh** as a result of changes in [*gas price from RM 10.7/mmbtu to RM 16.7/mmbtu and fuel oil price from USD85/tonne to USD110/tonne*] respectively. This increase will be pass-through in the second six (6) month period (FCPT 1);
- In the first six month period of the Regulatory Year, the Other Generation Specific Cost has increased by [**RM278.67 million or 0.58 sen/kWh**]. This increase will be pass-through in the following six month period (GSCPT 1); and
- Any over or under recovery of the collected FCPT1 and GSCPT 1 from the Audited Actual Fuel and Other Generation Specific Costs will be adjusted accordingly in the subsequent six month period (FCPT 2 and GSCPT 2).

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Fig: Example of the fuel price adjustment (FCPT1)

	First Regulatory Year		Second Regulatory Year	
	1st. 6 month	2nd. 6 month	1st. 6 month	2nd. 6 month
Estimated Actual Fuel Cost for each period (To be calculated on month 4, based on 3 month actual and 3 month forecast) - [For illustration purpose the actual gas price is RM16.7/mmbtu, Fuel oil USD 110/Tonne and RM/USD - 3.12]				
EAFC_g (Estimated actual gas cost based on generation mix and price)	4,409.89	4,409.89	4,653.41	4,653.41
EAFC_c (Estimated actual fuel oil cost based on generation mix and price)	4,658.40	4,658.40	4,854.78	4,854.78
EAFC (Total estimated actual fuel cost)	9,068.30	9,068.30	9,508.19	9,508.19
EAUS (GWh) - Estimated Actual Unit Sold	49,665.78	49,665.78	50,947.63	53,027.12
Actual Fuel cost component (sen/kwh)	18.26	18.26	18.66	17.93
Original Forecast of Fuel Cost for each period derive based on assumed generation mix, fuel price and unit sold at the time the Base Tariff was established i.e gas at RM10.7/mmbtu, Fuel oil at USD85/tonne and RM/USD = 3.12				
FFC_g (Forecast gas cost based on assume generation mix and price)	2,825.50	2,825.50	2,981.53	2,981.53
FFC_c (Forecast fuel oil cost based on assume generation mix and price)	3,599.68	3,599.68	3,751.42	3,751.42
FFC (Forecast Fuel Cost)	6,425.18	6,425.18	6,732.95	6,732.95
Sale Forecast (Gwh)	49,665.78	49,665.78	50,947.63	53,027.12
Forecast Fuel Cost component (sen/kWh)	12.94	12.94	13.22	12.70
Fuel cost Variation	2,643.12	2,643.12	2,775.24	2,775.24
Fuel cost Variation (Sen/kWh) - (To be Pass-Through in the following 6 month period)	5.32	5.32	5.45	5.23
FCPT 1		5.32	5.32	5.45

Fig: Example of the fuel price adjustment (FCPT2)

	First Regulatory Year		Second Regulatory Year	
	1st. 6 month	2nd. 6 month	1st. 6 month	2nd. 6 month
Approved FCPT1 (sen/kWh)	-	5.32	5.32	5.45
EAUS (GWh) - Estimated				
Actual Unit Sold		49,665.78	50,947.63	53,027.12
Total FCPT 1 Collection		2,643.12	2,711.34	2,888.52
Audited Actual Fuel Cost Variation (Available at the end of 2nd six month period)	2,510.96	2,510.96	2,636.48	2,636.48
Audited Actual Unit Sold (Available at the end of 2nd 6 month period)	49,665.78	49,665.78	50,947.63	53,027.12
(Over)/Under recovery of Fuel Cost Variation			(132.16)	(200.37)
FCPT 2 (Over)/Under recovery of Fuel Cost Variation (sen/kWh)	-	-	(0.27)	(0.40)
FCPT = FCPT 1+FCPT 2		5.32	5.06	5.04

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Fig: Example of Other Generation Specific Cost adjustment (GSCPT)

	First Regulatory Year		Second Regulatory Year	
	1st. 6 month	2nd. 6 month	1st. 6 month	2nd. 6 month
EASGC (Estimated Actual Other Generation Specific Cost)	5,852.13	6,062.06	6,062.06	6,077.75
FSGC (Forecast Other Generation Specific Cost)	5,573.46	5,773.39	5,773.39	5,788.33
Increase /(Decrease) in Other Generation Specific Cost	278.67	288.67	288.67	289.42
EAUS (GWh) - Estimated Actual Unit Sold	49,665.78	49,665.78	50,947.63	53,027.12
Increase /(Decrease) in Other Generation Specific Cost (sen/kWh)	0.561	0.581	0.567	0.546
SGCPT 1 (Other Generation Specific Cost Pass-Through)		0.561	0.581	0.567
Collection for Variation in Other Generation Specific Cost		278.67	296.12	300.45
Audited Actual Other Generation Specific Cost (Available at the end of 2nd 6 month period)	5,910.66	6,122.68	6,122.68	6,138.53
Audited Actual Unit Sold (Available at the end of 2nd 6 month period)	49,665.78	49,665.78	50,947.63	53,027.12
Under/(Over) Recovery of Variation in Other Generation Specific Cost			58.52	53.17
SGCPT 2 - Under/(over) Recovery of Other Generation Specific Cost (Sen/kWh)			0.12	0.10
SGCPT - (Total Other Generation Specific Cost Pass-Through)		0.56	0.70	0.67
Single Buyer Base Tariff [??]	21.53	24.63	24.63	24.63
FCPT 1		5.32	5.32	5.45
FCPT 2		-	(0.27)	(0.40)
SGCPT 1		0.56	0.58	0.57
SGCPT 2		-	0.12	0.10
Total Single Buyer tariff		30.51	30.38	30.34
Single Buyer Total Revenue		15,153.27	15,479.09	16,089.67
Single Buyer Total Generation Specific Cost		15,190.98	15,630.88	15,646.72
		(37.71)	(151.79)	442.95

3.2 Fuel cost and Other Generation Specific Cost adjustment

The ST will expect the Single Buyer to submit the following:-

- Detailed Estimated Actual Generation cost report for the current six month period of the Regulatory Term based on 3 month actual figure and 3 month estimated figure no later than first week of month 4 of the relevant six month period. This generation cost report will present (i) detailed calculation of the estimated actual Fuel Cost and Other Generation Specific Cost incurred by the Single Buyer under the PPAs and the SLAs such as capacity payments, fuel costs, incentives or bonus payment etc.. (ii) all costs incurred for the procurement of fuel oil and gas under various fuel oil and gas supply contracts by the IPPs and SESB with its fuel suppliers
- As soon as available but not later than month 4 of the current six month period, the Single Buyer should provide audited report on actual Fuel Cost, Generation Specific Costs, Unit Sold and Revenue collected based on Single Buyer Tariff, FCPT 1 and GSCPT 1 for the preceding six month period. This is to ascertain the amount of over or under recovery of changes in fuel and Generation Specific costs (FCPT 2 and GSCPT 2)

Six month actual revenue

The actual revenue for the six month period should be based on the Single Buyer Tariff, FCPT 1, GSCPT 1, FCPT 2 and GSCPT 2 and actual sales of electricity to customers. The actual generation specific revenue for the Single Buyer should reflect the generation specific revenue received from Customer Services over the relevant six month period.

Explanation of variances

The report should include a detailed explanation of the variances between actual costs of electricity procurement and generation revenue based on the Single Buyer tariff.

Proposed tariff adjustment

The ST proposes that any adjustments to the Fuel Cost and Other Generation Specific Cost to account for the difference in actual cost and forecasted cost should be implemented in the immediate next six month period. As the actual cost is not available in the immediate six month period it is proposed the pass-through will be based on estimated actual cost and over or under recovery of cost variation will be adjusted accordingly in next preceding six month period as and when the audited actual figure is available

Audit requirement

The ST will require the fuel cost report prepared by the Single Buyer to be certified as correct by a reputable audit company.

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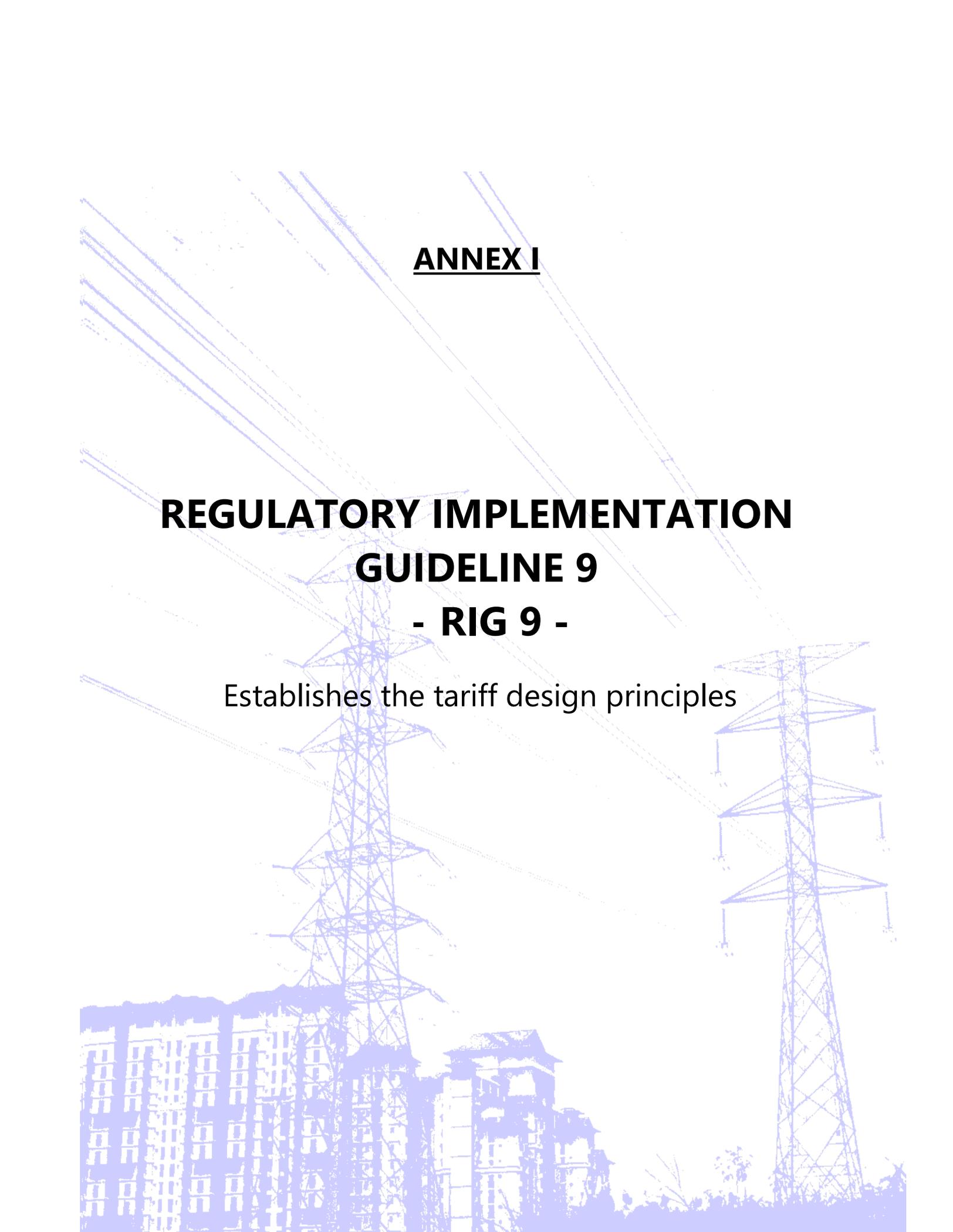
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3.3 Fuel Subsidy

The ST will review the tariff adjustment and recommend to Government the amount of fuel subsidy in case the ICPT is not aligned with Government policy concerning impacts on the customer.

3.4 Approval of proposed tariff adjustment

The ST will review the tariff adjustment as proposed by the Single Buyer pursuant to the Fuel Cost Adjustment and Other Generation Specific Cost Adjustment and finalise its decision no later than 30 working days after receipt of the Estimated Actual Generation Cost reports. Following the ST's final decision, ST will recommend its decision to the Minister for approval.



ANNEX I

**REGULATORY IMPLEMENTATION
GUIDELINE 9**

- RIG 9 -

Establishes the tariff design principles

1. Objective

The objectives of RIG 9 are as follows:

- Set out the principles to be followed by SESB when proposing prices; and
- Establish the annual price approval process.

2. Pricing principles

There are two overarching principles that should be applied by SESB when proposing tariffs, and which will form the basis for the ST's assessment of pricing proposals:

- **Cost recovery:** Prices should allow SESB to recover its operating and maintenance costs and achieve an appropriate rate of return on its investments, ensuring the financial viability of the regulated business; and
- **Cost reflectivity (allocative efficiency):** Prices should reflect the cost of services (that is, the costs imposed on SESB by electricity consumers), thereby providing appropriate incentives for customers concerning how and when they use electricity.

2.1 Cost recovery

Cost recovery is addressed via the Tariff Setting Framework and form of price control, as set out in Regulatory Implementation Guideline Number 2 (RIG 2), and the establishment of Annual Revenue Requirements, as set out in Regulatory Implementation Guideline Number 3 (RIG 3).

2.2 Cost reflectivity

Economic efficiency suggests that prices for a customer group should be set between an upper bound representing stand-alone costs and a lower bound representing avoidable or incremental cost, where:

- **Stand-alone cost** is the total cost SESB would incur if it provided services only to the customer group in question, with no other service provided to any other customer group; and
- **Avoidable cost** is the cost that would be avoided by not serving a particular customer group.

There is no single generally accepted method for calculating stand-alone cost or avoidable cost, and in practice there is likely to be a wide range of potential tariffs and tariff structures that would fall within these bounds.

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In justifying tariffs and tariff components, the ST expects that SESB will have regard to an accepted methodology for estimating the cost of serving customers, such that prices reflect the impact of electricity use by customers on decisions by SESB concerning upgrades and augmentations to generation and transmission infrastructure (that is, the Long Run Marginal Cost (LRMC) of supply). For example, costs of generation passed from the Single Buyer to the Customer Services business entity (and on to final customers) should reflect the load profile of customer groups or segments and SESB's associated network planning considerations (such as type of generation required to serve that customer group).

LRMC is generally estimated on either an incremental or greenfields basis.

Incremental methods for estimating LRMC include the Average Incremental Cost (AIC) and Marginal Incremental Cost (MIC) approaches. These approaches are entirely forward looking and ignore sunk costs (by assuming there is existing plant available to meet demand). Where there is excess capacity in a system, or the next supply augmentation is some way off, estimates of incremental LRMC may be very low, suggesting that very low variable usage charges should be applied. Very low variable charges may limit the effectiveness of tariffs in terms of:

- Customers' ability to exercise control over their bills by changing usage patterns; and
- The provision of incentives for customers to use energy efficiently.

The greenfields approach (sometimes referred to as the stand-alone load or long run average cost (LRAC) approach) assumes there is currently no plant available to meet demand, and involves the estimation of an optimised replacement cost to meet existing and future demand.

The ST is open to considering alternative approaches to estimating the cost of serving customers that meet the objectives of the pricing principles. However, given the uncertainty involved in appraising costs over a long-term timeframe, any estimates of LRMC should be treated with caution. Regardless of the approach applied, prices should still fall within the bounds of stand-alone and avoidable cost and send appropriate signals to customers about how and when they consume electricity.

2.3 Implementation issues

In addition to the high level pricing principles outlined above, SESB must have regard to the following issues when developing its tariff structure proposals:

- **Recovery of costs:** SESB's prices should be structured so as to ensure that it recovers its revenue requirement for each business entity over the Regulatory Term.
- **Consistency with Government policy:** SESB's prices should be consistent with any applicable Government policy concerning impacts on vulnerable customer groups and

economic and regional development issues, including employment and investment growth.

- **Customer impacts:** Where adverse impacts on customers from changes to, or increases in, tariffs are identified, SESB should provide details of its strategies for addressing customer impacts.
- **Subsidy:** The ST may consider recommending to the Government the Tariff Support Subsidy or Fuel Subsidy in case the required tariff is not acceptable by the Government
- **Transparency and simplicity:** For any price signals to be effective, tariffs must be able to be readily understood by customers. Highly complex tariff structures, while potentially being more cost reflective, may not be effective in influencing customer behaviour if they are not clearly understood.
- **Costs and benefits of changes to tariff structures:** Where SESB proposes to revise its tariff structures it should take into account the costs of implementing the new tariffs (such as changes to billing systems and informing and educating customers) with the anticipated benefits in terms of improving cost reflectivity or incentives for customers to change behaviour.

3. Tariff setting process

This section of the guideline sets out the annual tariff approval process for within-period tariff adjustments.

As noted in RIG 3, the final tariff paid by customers (the total average electricity tariff) is set by the Customer Services business entity and is the sum of all Component Average Tariffs for each of the SESB business entities. Customer Services should allocate the costs imposed by customers on SESB business entities to the tariffs charged to specific customer groups based on information from each business entity about the cost of providing services to those customer groups. SESB's regulatory submission should also set out detailed information that demonstrates the calculation of the total average electricity tariff, including, for each tariff category and tariff component:

- The amount of the tariff
- Criteria for designing tariff band and categories/classes
- Customer numbers
- Current and expected volumes
- Current and expected revenue.

The following worked example shows how the total average tariff is calculated from a simple case where the regulated entity has two separate tariff categories, each with a number of components.

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Fig: Example of calculation of the total average tariff

	Unit	Charge	Sales (MWh)	Revenue (RM)
Tariff category 1: domestic tariff				
<i>Customer numbers 20,000</i>				
First 100 kWh	sen/kWh	15	400	60,000
101 - 200 kWh	sen/kWh	20	2,500	500,000
201 kWh and above	sen/kWh	25	11,000	2,750,000
Minimum monthly charge	RM	3		
Tariff category 2: industrial tariff				
<i>Customer numbers 10,000</i>				
Peak charge (9am to 3pm)	sen/kWh	33	66,000	21,780,000
Off-peak charge (3pm to 9am)	sen/kWh	25	40,000	10,000,000
Demand charge	RM/kW	20	NA	10,000
Total			119,900	35,100,000
Total average tariff	sen/kWh	29.27		

Note: the revenue and sales for the minimum monthly charge are included in the First 100 kWh block of the domestic tariff

Any changes in components of the total average electricity tariff due to Revenue Cap adjustments or Actual Cost adjustments for individual business entities will flow through directly to prices charged to final customers.

The total average electricity tariff constraint allows SESB to increase (or decrease) some individual tariffs for customer groups by more or less than others, so long as the total average electricity tariff condition is met. The ST will set side constraints on the movement of individual tariffs to guard against customers being subject to price shocks.

As noted in RIG 2, under the proposed revenue cap and actual cost arrangements for the Transmission, System Operation and the Single Buyer business entities, the period of tariff adjustment are as follows:

- **Transmission revenue cap adjustments:** It is proposed that this adjustment is done on regulatory term basis;
- **System Operations revenue cap adjustment:** It is proposed that this adjustment is done on regulatory term basis;
- **Single Buyer fuel price adjustment (for the generation specific tariff component):** It is proposed that this adjustment is done every six months;
- **Single Buyer actual cost adjustment (for the other generation specific tariff component):** It is proposed that this adjustment is done every six months; and

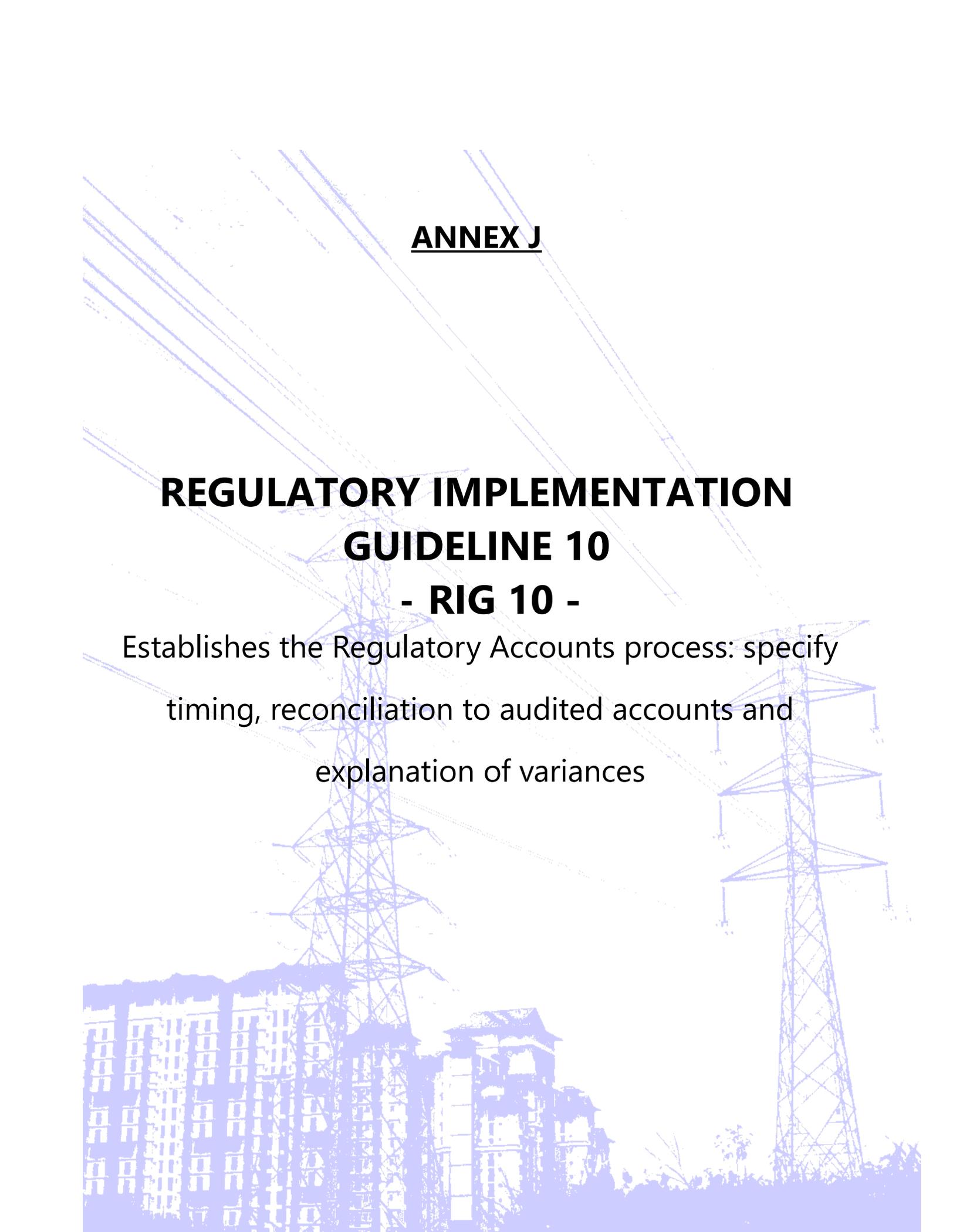
- **Single Buyer Operations revenue cap adjustment (for the other operational cost specific tariff component):** It is proposed that this adjustment is done on regulatory term basis.

The ST proposes that rebalancing of tariffs will only occur at regulatory term intervals, with the six month adjustments for fuel prices and Single buyer actual generation costs being enacted as a direct and proportional pass-through to all tariffs.

3.1 Tariff adjustments

The following process is proposed for tariff adjustments:

- Two months prior to the end of the regulatory year, SESB will be required to submit its proposed tariff schedule to the ST, with any rebalancing proposals accompanied by evidence of compliance with the pricing principles and implementation issues. Adjustments for revenue under or over recovery under the revenue cap arrangements will be based on an estimate of revenue for the current regulatory term (combining the most recent actual data and forecasts for the remainder of the regulatory term). Any difference between estimated revenue and actual revenue will need to be accounted for in revenue cap adjustments in subsequent regulatory terms.
- The ST will then assess the tariff proposed against compliance with the total average electricity tariff constraint, and the pricing principles and implementation issues.
- Where inconsistencies with the total average electricity tariff constraint, pricing principles or implementation issues are identified, the ST may request clarification from SESB or require SESB to re-submit its tariff proposal.
- Following approval by the ST, SESB will publish its approved tariffs on its website at least 10 business days prior to the commencement of the next regulatory year.



ANNEX J

**REGULATORY IMPLEMENTATION
GUIDELINE 10**

- RIG 10 -

Establishes the Regulatory Accounts process: specify timing, reconciliation to audited accounts and explanation of variances

1. Objective

The objective of RIG 10 is to set out the framework for the development of regulatory accounts for each of SESB's regulated business entities¹. The purpose of the Regulatory Accounts will be to assist in the assessment of SESB's actual performance in terms of:

- financial benchmarks, operating and capital expenditures that make up the revenue requirement; and
- operational performance standards and key performance indicators, developed in accordance with the framework is set out in RIG 6.

2. Background

The regulatory framework proposed by the ST in RIG 2, RIG 3 and RIG 4 will rely on the submission of a range of information by the SESB business entities to build up a revenue requirement and set prices for the Regulatory Term, including forecasts of:

- capital expenditure and operating expenditure for each SESB business entity;
- revenue for each business entity; and
- operational performance and performance against indicators and targets relating to network performance and customer service.

During the course of the Regulatory Term, and at the end of the Regulatory Term, the ST will assess actual outcomes against forecasts and benchmarks for the purposes of:

- updating the regulatory asset base (RAB) for actual capital expenditure and customer contributions and depreciation (the process for updating the RAB is set out in RIG 3)²;
- making price adjustments for actual cost outcomes for the Single Buyer Generation under the Actual Cost regime (the Actual Cost regime is set out in RIG 2)³;
- making price adjustments for actual revenue outcomes for the Transmission, System Operations and Single Buyer Operations under the Revenue Cap regimes (see RIG 2);
- making price adjustments for actual operating expenditure outcomes the efficiency carry over scheme (see RIG 3); and
- forecasts of operational performance and performance against indicators and targets relating to network performance and customer service (as set out in RIG 6).

In addition to audited financial accounts, the ST is proposing to require the SESB business entities to submit Regulatory Accounts to assess actual performance against the forecasts of

¹ The five SESB business entities are specified in RIG 1.

² The process for updating the RAB is set out in RIG 3.

³ The Actual Cost regime is set out in RIG 2.

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Establish Regulatory Accounts Process

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operating expenditure, capital expenditure and operational performance which form the basis of prices for the Regulatory Term.

Regulatory Accounts are required because while audited financial accounts provide a description of the financial performance of the business as a whole, a number of items are treated differently for regulatory purposes (for example, regulatory depreciation of the regulatory asset base (RAB) and the treatment of customer contributions). Also, there will be a range of expenditure and revenue items included in the financial accounts that relate to services that are not subject to regulation and therefore should be excluded from the Regulatory Accounts and development of prices for the SESB business entities.

Regulatory Accounting information is critical to enable to ST to assess both the past performance of the SESB business entities, and to inform the establishment of the revenue requirement, operational performance targets and prices in future Regulatory Terms.

In addition, the process of maintaining Regulatory Accounts will assist in the implementation of the regulatory framework by providing a clear link between the inputs used for regulatory pricing purposes and the financial statements of SESB as a whole.

3. Form of Regulatory Accounts

The Regulatory Accounts should be drawn from the audited financial accounts of the SESB business entities. However, as noted above, there are a number of differences between financial accounting information and regulatory data.

The translation of business performance data from the financial accounts to the Regulatory Accounts should be consistent with the ST's proposed regulatory framework set out in the Regulatory Implementation Guidelines, in particular:

- The revenue requirement principles in RIG 3;
- The principles of allocating joint costs in RIG 7; and
- The pricing principles in RIG 9.

The format of the Regulatory Accounts will be the same as that used for the data input templates in Appendix 1 to RIG 5. In particular, the Regulatory Accounts should include the same level of detail with regard to categories of operating and capital expenditure, the breakdown of the RAB, and allocation of joint costs as has been included in the original regulatory submission from the SESB business entities that make up the revenue requirement.

This will ensure that the ST is readily able to compare the actual performance of the SESB entities against the forecasts used to establish prices and performance standards.

3.1 Development of Regulatory Accounts

The Regulatory Accounts submitted by SESB should be accompanied by a submission setting out the process by which the Regulatory Accounts were drawn from the audited financial accounts, and any adjustments made in the process of translation.

The key issues to be covered will be:

- a description of how expenditures and revenues for regulated services have been separated from expenditures and revenues for services provided by SESB that are not subject to regulation (if any). This is a key principle of the regulatory framework, as it is important that services provided by SESB that are not subject to regulation (as they are provided in a competitive environment) are not cross-subsidised by revenue earned from regulated services; and
- confirmation that the cost allocation methodology used in translating joint costs from the financial accounts to the Regulatory Accounts is consistent with SESB's cost allocation methodology (as set out in RIG 7).

The translation of data from the audited financial accounts to the Regulatory Accounts (including compliance with the joint cost allocation methodology) should be audited by a reputable accounting firm, preferably the same firm that has audited SESB's financial statements.

FIG: Development of Regulatory Accounts



3.2 Explanation of variances

SESB should provide a submission including a detailed explanation of such variances where variances occur between the actual operating expenditure, capital expenditure and operational performance data in the Regulatory Accounts and the forecast data provided to the ST in the templates in Appendix 1 to RIG 5 prior to the commencement of the Regulatory Term.

The explanation of variances between the forecast and actual expenditure and performance should include (but not be limited to) descriptions of any operating cost over runs or efficiency gains, changes to the timing or amount of capital expenditure and forecasting error with respect to electricity sales.

3.3 Commentary on operational performance

The Regulatory Accounts should also include a detailed commentary about the operational performance of the SESB business entities, encompassing network performance and performance against customer service standards. This commentary should be in the form of a review by management highlighting key areas of concern for the business and provide details of any programs or revisions to processes to be implemented by SESB to address these concerns.

4. Implementation process

The ST proposes the following implementation plan:

- 2 months following the finalisation of SESB's financial accounts, SESB will be required to provide the ST with its Regulatory Accounts;
- The Regulatory Accounts will be in the same format as the data supplied in the initial submission for the Regulatory Term, as set out in the templates in Appendix 1 (see RIG5); and
- The Regulatory Accounts must be audited by a reputable firm – preferably the same firm used by SESB for auditing its financial accounts and include a declaration by senior management of SESB confirming the veracity of the Regulatory Accounts and accompanying submissions.

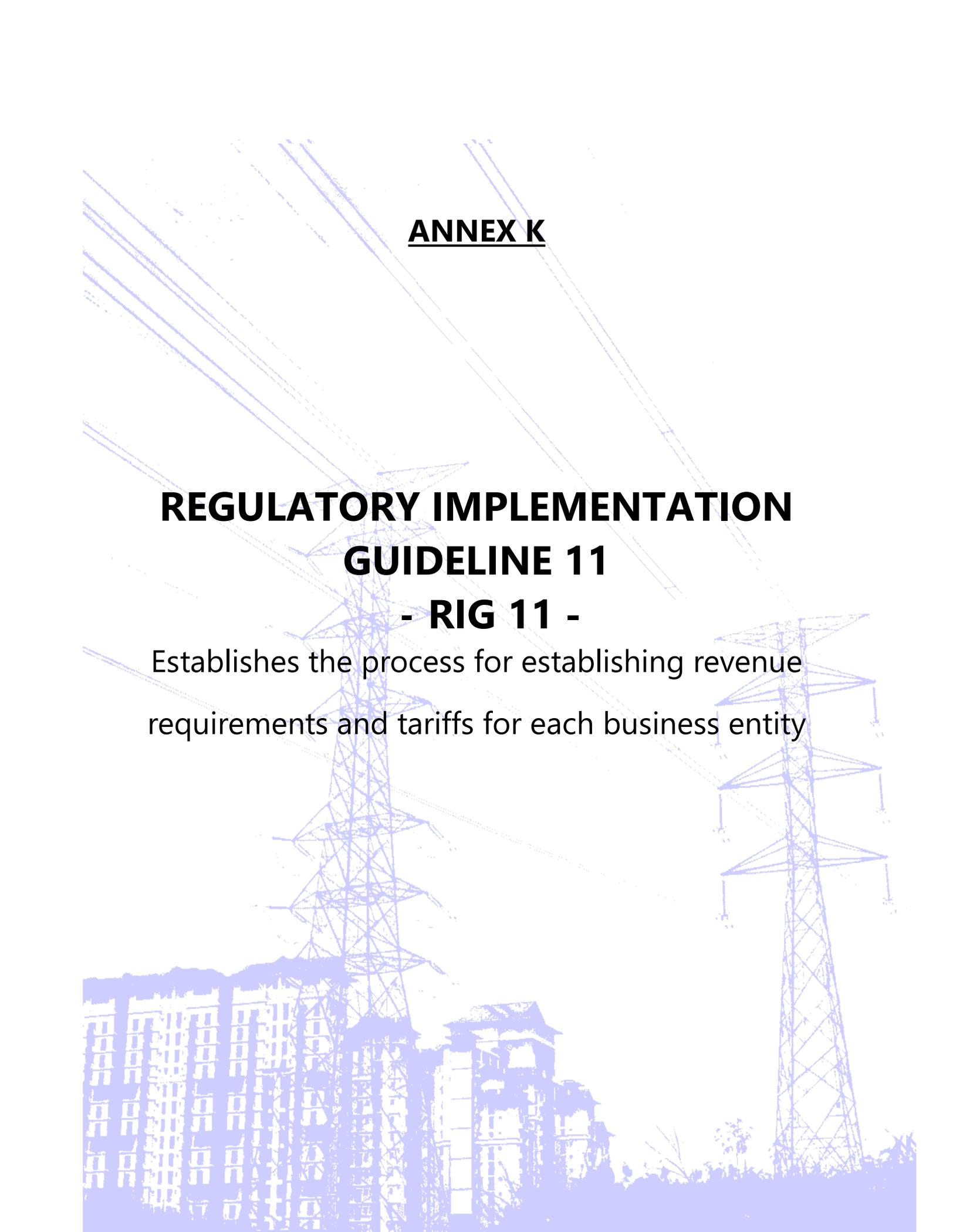
4.1 Review of regulatory accounts

The Regulatory Accounts and accompanying reports submitted by SESB on its performance will also allow the ST to assess trends in expenditure and revenue and inform the assessment of future regulatory proposals by SESB concerning forecasts of operating and capital expenditure and performance targets in subsequent Regulatory Terms. The audited Regulatory Accounts will be primarily used by the ST to:

- Update the RAB with actual capital additions made over the Regulatory Term (including deductions for customer contributions) and ensure that the regulatory depreciation applied is appropriate;
- Review operating expenditure and the efficiency carry over amounts for the efficiency carry over scheme;
- Review revenues and costs for the purposes of making adjustments under the Revenue Cap and Actual Cost regimes; and
- Assess SESB's performance against its targets for performance indicators (as set out in RIG 6), and in subsequent Regulatory Terms, inform the incentive or penalty amounts associated with either meeting or falling short of the targets.

In assessing the audited Regulatory Accounts, the ST may request further details from SESB on any particular areas of concern or where it considers that variances between the forecast data in the revenue requirement templates and the Regulatory Accounts are not adequately explained.

It should also be noted that while the Regulatory Accounts will provide a key input into the ST's assessment of actual outcomes, the ST will still assess past capital expenditure and operating expenditure undertaken by SESB to ensure that it is prudent and efficient.

The background of the slide features a blue-tinted image of high-voltage power lines and transmission towers stretching across the sky. In the lower portion of the image, a city skyline with several buildings is visible. The overall aesthetic is clean and professional, with a focus on infrastructure.

ANNEX K

REGULATORY IMPLEMENTATION GUIDELINE 11

- RIG 11 -

Establishes the process for establishing revenue requirements and tariffs for each business entity

1. Objective

The objective of RIG 11 is to outline the regulatory review process to be followed for the first regulatory period.

2. Overview of regulatory review process

Following the finalisation of the Regulatory Implementation Guidelines (RIG) and price review templates, the regulatory review process will comprise the following key elements:

- SESB to propose service standards for each of its business entities (see RIG 6 on operating performance indicators). The ST will decide upon SESB's proposed service standards before considering required revenue and prices;
- SESB to develop its proposal for its annual revenue requirement to meet its service standards, including targets for operating and capital expenditure (see RIG 3 on revenue requirement principles) and a rate of return of capital expenditure. The ST will assist SESB with necessary workshops and guidance as required on the development of its proposal;
- The ST to approve prices proposed by SESB which will allow it to earn its required revenue, given forecast demand (see RIG 2 on the tariff setting framework and RIG 9 on pricing principles). Following a draft decision on prices, the ST will consult with relevant stakeholders and may also consider submissions before making its final decision; and
- In review the proposal, the ST may consider a Tariff Support Subsidy for Government's approval, in case the required tariff is beyond Government's expectation.

2.1 Timeframes and key milestones

The table below outlines indicative dates and timeframes for each stage of the review and key milestones.

In addition to the two (2) months period for SESB to develop its service standards, the ST will allow SESB four (4) months to develop its proposal for the review in recognition of the additional time that may be required to liaise with Government and obtain any necessary Ministerial approvals. These are indicative timeframes only, however, the ST is mindful that it is important to minimise the administrative costs of undertaking regulatory reviews by ensuring they run to schedule.

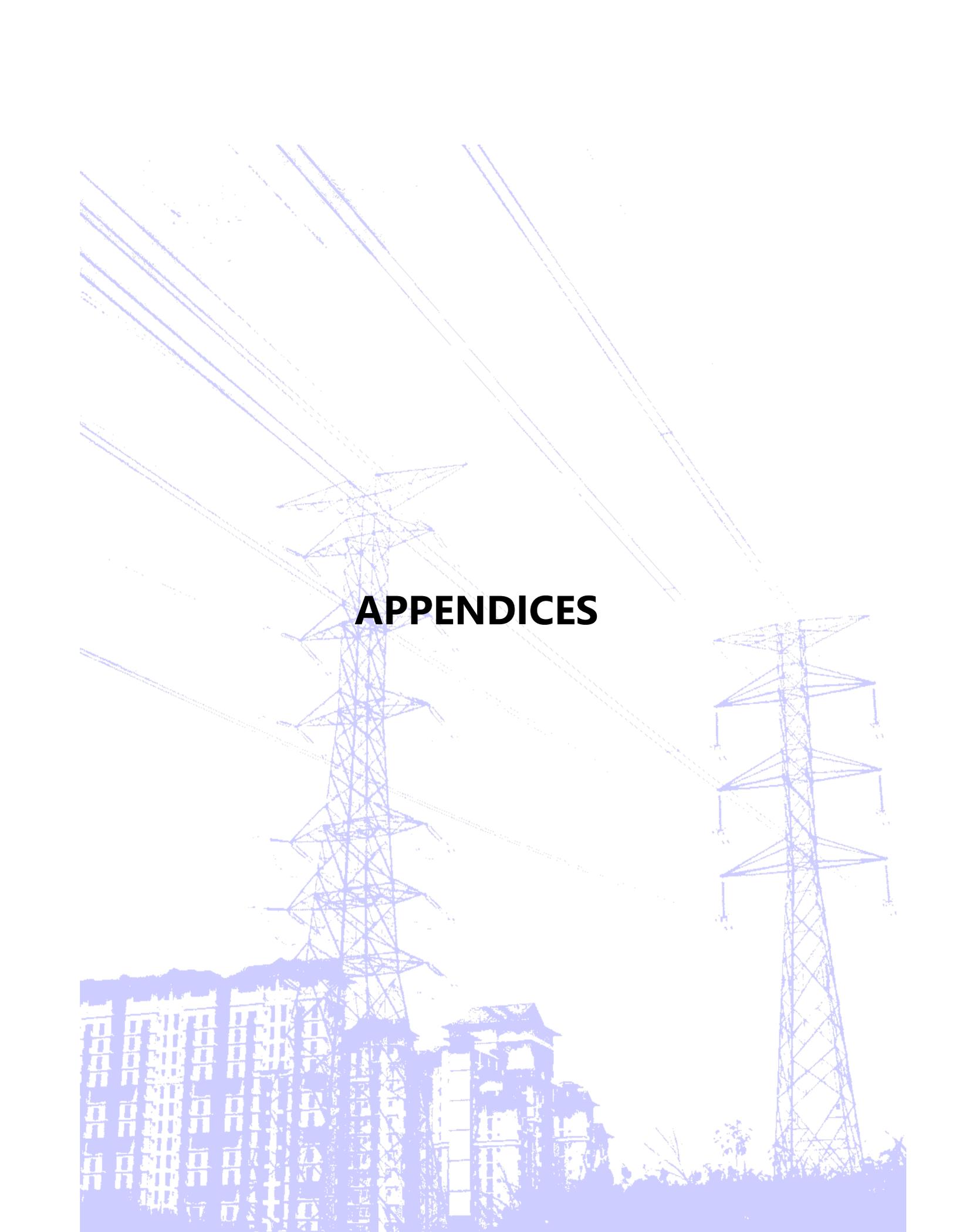
RIG 11

Establish Process for Establishing Revenue Requirements and Tariffs

January 2016

Table: Process of review

Stage	Indicative dates	Process
Stage 1: RIGs	January 2016	ST to issue final RIG to SESB
Stage 2: Single Buyer Rules	June 2016	Study on Single Buyer Rules completed
Stage 3: Service standards	December 2015 – June 2016	SESB to develop proposed service standards and targets in accordance with RIG 6. Each of the SESB business entities will propose operational performance indicators, with a lower and upper bound performance target.
	July 2016	ST draft decision on service standards.
	August 2016	ST final decision on service standards. The ST will consult with the SESB business entities and other stakeholders as required in making its decision
Stage 4: SESB submission to review (4 months)	May 2016	SESB to prepare its submission covering four (4) years (Jan 2017- Dec 2020) to the review in accordance with the RIG and services standards
	(no later than) August 2016	SESB to provide the ST with completed Revenue Requirement Model and any relevant accompanying documentation
Stage 5: Draft decision (4 months)	June 2016 – September 2016	ST to assess SESB's proposal and make a draft decision on prices
Stage 6: Final decision (3 months)	October 2016	Following the release of the draft decision, the ST will consult with relevant stakeholders, including Government (the Ministry of Energy, Green Technology and Water – KeTTHA, the Economic Planning Unit – EPU), SESB and customer groups
	December 2016	The ST may also consider submissions from SESB and other parties on its draft decision The ST to release its final decision
January 2017 – December 2017		IBR trial run starts on Jan 2017 to Dec 2017 for one year SESB is to submit for Jan 2018 to Dec 2020 regulatory period for final approval (if necessary)
Jan 2018 – Dec 2020 : First Regulatory Period of Full Incentive-based Regulation Regime		



APPENDICES

SESB Revenue Requirement Model - Post Tax Nominal

Regulatory Economic Inputs

1 **Regulatory period** 4 Years

2 **Regulated Entity** SESB

3 **Timing** 1/09/2016 - 31/8/2020
 Enter commencement date of Regulatory Period

Start Date End Date	Base		Forecast		Trial Reg. Period		Regulatory Period - Forecast	
	1/09/2013 31/08/2014	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020
Start Date End Date	1/09/2013 31/08/2014	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020
Demand Forecast	12.80%	11.63%	11.63%	10.78%	11.25%	11.09%	10.82%	11.07%
Losses	0	0	0	0	0	0	0	0
Demand Forecast - Approved by authorities	1/05/2014	5,948,070	5,674,503	6,009,086	6,357,614	6,713,640	7,082,850	7,453,060
Tolerance level (No. of month)	6	OK	OK	OK	OK	OK	OK	OK

4 **Demand Forecast**

5 **Capital Expenditure Forecast**

Start Date End Date	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast	
	1/09/2013 31/08/2014	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020
Start Date End Date	1/09/2013 31/08/2014	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020
Capital Expenditure Input	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0
System Operation	0	0	0	0	0	0	0	0
Single Buyer Operation	0	0	0	0	0	0	0	0
Customer Services	0	0	0	0	0	0	0	0
Joint Cost	0	0	0	0	0	0	0	0
Input from Licence Condition	0	0	0	0	0	0	0	0
Generation	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0
System Operation	0	0	0	0	0	0	0	0
Single Buyer Operation	0	0	0	0	0	0	0	0
Customer Services	0	0	0	0	0	0	0	0
Joint Cost	0	0	0	0	0	0	0	0

FOREIGN EXCHANGE RATES

FOREX - RM / Forex	MVR	2012	2013	2014	2015	2016	2017	2018	2019	2020
1 USD	USD	3.1251	3.0000	3.8000	4.4000	4.4000	4.4000	4.4000	4.4000	4.4000
100 Yen	JPY	3.9743	3.6600	3.5600	3.3600	3.3600	3.3600	3.3600	3.3600	3.3600

FUEL PRICES

Base FUEL PRICES in normal units	2012		2013		2014		2015		2016		2017		2018		2019		2020	
	USD/tonne	RM/tonne																
MFO	693.65	684.54	156.63	1.92	406.63	406.63	406.63	1.92	406.63	406.63	406.63	1.92	406.63	406.63	406.63	1.92	406.63	406.63
Diesel	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
Coal	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00	95.00
Gas W	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40
Gas E	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
LNG	28.83	29.86	30.91	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96	31.96
MFO (in litre)	2.256	2.139	0.620	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864	1.864

Calorific Value	37.7912 mmbtu/tonne	MFO	0.96 MFO Density (kg/litre)
	0.03359 mmbtu/litre	Diesel	
	5000.00000 kcal/kg	Coal	
	0.2521 kcal/btu		

Note: Gas price is escalated until it reaches
 LNG (market price)
 LNG Regassification cost :
 Gas price fixed escalation
 Piped gas Escalation 'yes' =1, 'no' =0 from 2014
 LNG escalation

Customer Deposit

Base Year Closing Value	218,721,000	3%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deposit received in the Base Year																		

Operating Cost

	3%	2%	6%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Repairs & Maintenance (Including consumables)	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other general expenses	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Staff Costs	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Expenditure	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inflation - O&M		2%			2%			2%		2%			2%		2%			2%
Inflation Factor - O&M	1	1.02	1	1.04	1	1.06	1	1.08	1	1.10	1	1.13	1	1.15	1	1.18	1	1.21
Inflation - Staff Cost	-	4%	-	10%	-	4%	-	10%	-	4%	-	10%	-	4%	-	10%	-	4%
Inflation Factor - Staff Cost	1	1.04	1	1.14	1	1.19	1	1.31	1	1.36	1	1.50	1	1.65	1	1.81	1	2.00

Government Grant

- Receive during the year	94,140,000	7%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Release to income	68,406,000																	
Received in relation to Dist. Capex		30%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Received in relation to Others. Capex																		

6 Post-tax Nominal WACC

Selected Scenario		Low	Base	High
Risk free rate		4.00%	4.00%	4.00%
Debt margin		2.11%	2.34%	2.57%
Corporate tax		25.00%	25.00%	25.00%
Cost of debt		4.58%	4.75%	4.93%
Risk free rate		4.00%	4.00%	4.00%
Equity beta		0.920	1.429	1.429
Market Risk Premium		4.80%	4.80%	4.80%
Cost of equity		8.42%	10.86%	10.86%
Gearing = D/(D+E)		39%	55%	60%
WACC		6.92%	7.50%	7.30%
Post-tax Nominal WACC Selected		7.50%		

7 Customer Contribution

Base Year Closing Value	225,812,000
Contribution received in the Base Year	88,254,000

8 The latest Approved Average Tariff

	32.82 Sen/KWh
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9 Po Inputs

Single Buyer Generation Po Starting Price	72.28%	24.89 sen/kWh	1.16
Transmission Po Starting Price	14.14%	4.87 sen/kWh	0.23
System Operations Po Starting Price	0.08%	0.02560 sen/kWh	0.00
Single Buyer Operations Po Starting Price	0.04%	0.01311 sen/kWh	0.00
Customer Services Po Starting Price	13.47%	4.54 sen/kWh	0.22
Total Average Electricity Tariff Po Starting Price		34.44 sen/kWh	1.60
Approved tariff		34.44	
Adjustment Factor		0.29	OK
		0.00	OK

10 Input from Divisional Accounting Data

- Allocation of Corporate Cost to Transmission	1.230	70% of this cost will be reallocated to SO
	70%	Reallocated to SO
	55%	to SO
	45%	to SB

Unit sold FY2014
 Income (Audited)
 Profit After Tax

4,786,490,000.00
 1,570,230,000.00
 96,673,000.00

32.81 sen/kWh

OK
 OK

Division	Direct and Allocated Cost	Non-Tariff Rev.	Allocated Profit	Rev. Requirement (Tariff Income)	Po
Generation	1,817,140,000.00	699,120,000.00	18,199,580.00	1,136,219,580.00	23.74
Transmission	225,245,000.00	37,700,000.00	34,798,200.00	222,343,200.00	4.65
Distribution	343,020,000.00	175,018,000.00	43,675,220.00	211,677,220.00	4.42
Corporate	10,000.00	-	-	10,000.00	0.00
Total	2,385,395,000.00	911,838,000.00	96,673,000.00	1,570,230,000.00	32.81

INPUT FROM DIVISIONAL ACCOUNTING REPORT - FY2014

Non-Tariff Revenue	Generation	Transmission	Distribution	Corporate	Total
Other Income	290,000	160,000	15,800,000	0	15,670,000
Con Contribution	-	-	116,327,000	0	116,327,000
Goods & Services	-	-	13,411,000	0	13,411,000
Subsidy	683,020,000	37,540,000	29,489,000	0	683,020,000
Other Income & Finance Income allocated from Corporate	16,390,000	37,700,000	175,018,000	0	83,110,000
TOTAL Non-Tariff Revenue	699,120,000	37,700,000	175,018,000	0	911,838,000
Operating cost	Generation	Transmission	Distribution	Corporate	Total
Operating expenses	823,540,000	166,375,000	240,510,000	0	1,230,225,000
Operating cost allocated from Corporate	26,120,000	27,480,000	71,360,008	51,190,000	176,090,008
Forex	0	0	0	0	0
Forex (Gain)/Loss allocated from Corporate	-350,000	-680,000	-590,000	0	-1,620,000
Finance Cost allocated from Corporate	11,650,000	28,500,000	24,130,000	100,080,000	164,360,000
Transaction allocated from Corporate	1,810,000	3,570,000	3,070,000	8,450,000	8,450,000
Finance cost	0	0	4,740,000	-	4,740,000
IPP Cost	954,370,000	-	-	-151,220,000	803,150,000
TOTAL Operating Cost	1,817,140,000	225,245,000	343,020,000	-10,000	2,385,395,000
Allocated profit	Generation	Transmission	Distribution	Corporate	Total
Divisional profit	18,199,580.00	34,798,200.00	43,675,220.00	-	96,673,000
Return on Fixed Assets	3.1%	3.0%	4.4%	0.00%	3.5%
	23,738	4,645	4,422	0,000	96,673,000
Assets	588,890,000.00	1,159,940,000.00	998,100,000.00	-	2,746,930,000

IPP General Information

Name	Capacity (MW)	Type (Base, Mid, peaking)	Fuel	Average net heat rate (Btu/kWh)	PPA/SLA start date (mm/yyyy)	PPA/SLA end date (mm/yyyy)	VOIM RM/kWh	FOR	CRF - Tier 1	CRF - Tier 1 - (No. of Yrs)	CRF - Tier 2
1 IPP Rugading CC	195	Base	Gas W	8,072.3	30/04/2011	21/04/2032	0.0226	5.79	36.50	12	24
2 IPP SBPC Gas	100	Base	Gas W	8,861.3	13/08/2008	31/05/2029	0.0138	5.19	60.00	12	50
3 IPP Teluk Saut Gas	190	Base	Gas W	9,003.8	25/10/2008	26/10/2029	0.0127	14.41	39.32	15	9
4 IPP ARL MFO	44	Mid	MFO	8,636.0	31/10/1995	31/08/2017	0.0083	14.82	63.56	12	39
5 IPP Serudong MFO	36	Mid	MFO	8,189.6	02/12/1996	03/12/2017	0.0083	14.82	63.56	12	37
6 IPP SPC MFO	32	Base	MFO	8,189.6	05/02/1999	31/08/2012	0.0185	14.60	48.00	12	27
7 IPP Libaran MFO	15	Peaking	MFO	8,047.4	05/12/1998	31/12/2019	0.0134	14.48	48.10	12	27
8 IPP Sutra H. DG	34	Base	Diesel	10,203.9	01/11/1998	31/08/2014	0.0144	35.48	-	0	0
9 IPP SPR Energy Gas	100	Peaking	Gas W	8,938.5	31/10/2013	30/10/2034	0.0140	5.20	55.85	12	28
10 IPP Kimanis Gas	285	Base	Gas W	7,840.8	01/04/2014	31/03/2035	0.0232	5.95	53.00	15	32
11 east CC10	0	Base	Gas E	7,839.8	29/03/2025	28/03/2046	0.0165	6.67	52.00	15	39
12 SREP Kadamalan Hydro	2	Base	SREP	-	01/08/2009	31/08/2030	0.2400	-	-	0	0
13 SREP Pangapuyan Hydro	4.5	Base	SREP	-	10/01/2010	31/08/2031	0.3000	-	-	0	0
14 SREP TSH BioEnergy	10	Base	SREP	-	17/02/2005	31/08/2025	0.3000	-	-	0	0
15 SREP Seguntor BioEnergy	10	Base	SREP	-	31/03/2009	31/03/2030	0.3000	-	-	0	0
16 SREP Kinabio Power	10	Mid	SREP	-	26/01/2009	26/01/2030	0.2100	-	-	0	0
17 East Aero B. Sapt. Diesel	60	Base	Diesel	10,270.1	01/09/2018	31/08/2019	0.0165	5.95	53.00	15	32
18 East Aero L. Datu	30	Peaking	Diesel	10,270.1	01/02/2017	31/01/2038	0.0165	6.67	52.00	15	39
19 east Aero B. Sapt. Gas	60	Base	Gas E	10,270.1	31/08/2019	30/08/2039	0.0165	6.67	52.00	15	39
20 west CC100 (KPSB Model)	300	Base	Gas W	7,817.3	15/04/2030	14/04/2051	0.0165	5.20	55.85	12	28
21 Cash Horse	10	Base	SREP	-	28/03/2013	31/08/2034	0.1700	-	-	0	0
22 east Teck Guah	3	Base	SREP	-	01/09/2014	31/08/2027	0.2100	-	-	0	0
23 ECO-Blomass	10	Base	SREP	-	01/09/2016	31/08/2037	0.2100	-	-	0	0
24 Cahaya BumiJasa	3.8	Mid	SREP	-	28/11/2016	27/11/2037	0.2100	-	-	0	0
25 East OEG (Our Energy Group)	2	Mid	SREP	-	26/01/2014	25/01/2035	0.2100	-	-	0	0
26 East QL Biogas	2	Mid	SREP	-	25/01/2015	24/01/2036	0.2100	-	-	0	0
27 East TSH Biogas	2.7	Base	SREP	-	26/01/2015	25/01/2036	0.2100	-	-	0	0
28 east OC60	0	Base	Gas E	7,840.8	28/03/2046	27/03/2067	0.0083	5.20	55.85	12	28
29 east CC100 (KPSB)	300	Base	Gas E	7,840.8	26/01/2019	25/01/2040	0.0083	5.20	55.85	12	28
30 west CC10	100	Base	Gas W	7,840.8	26/01/2025	25/01/2046	-	-	-	0	0

SESB Generation General Information

Name	Capacity (MW)	Mode of Operation	Type (Base, Mid, peaking)	Fuel	Average net heat rate (Btu/kWh)	PPA/SLA Start date (mm/yyyy)	Contract end date (mm/yyyy)	VOIM RM/kWh	FOR	CRF - Tier 1	CRF - Tier 1 (No. of Yrs)	CRF - Tier 2	Average Remaining life of NSLA Assets
1 Patrau Patrau OCGT	60	SLA	Base	Gas W	13,242	01/09/1995	31/08/2030	0.0306	7.11	25.8	4,0000	20,9100	-
2 Patrau Patrau CC	44	SLA	Base	Gas W	9,213	01/09/1992	31/08/2027	0.0148	7.09	28.5	4,0000	23,2800	-
3 Melawa DG	14	NSLA	Mid	Diesel	9,443	01/09/1994	31/08/2015	0.0148	7.09	64.1	-	-	0.15
4 Melawa GTM	18	NSLA	Mid	Diesel	11,469	01/09/1995	31/08/2013	0.0148	7.09	0.0	-	-	-
5 Pangli Hydro	69	SLA	Base	Hydro	-	01/09/1984	31/08/2034	0.0134	7.09	46.9	12,0000	22,6400	-
6 Upper Padas Hydro	180	-	Base	Hydro	-	14/05/2023	13/05/2073	0.0000	26.40	65.0	-	-	-
7 Liwagu Hydro	-	-	Base	Hydro	-	01/09/2025	31/08/2075	-	26.40	65.0	-	-	-
8 Mini Hydro East	2	NSLA	Mid	Hydro	-	01/09/1991	31/08/2020	0.0025	7.09	64.1	-	-	0.06
9 Tawau DG	4	NSLA	Peaking	MFO	8,626	01/09/1984	31/08/2013	0.0189	7.09	64.1	-	-	-
10 Tawau GT1	5	NSLA	Peaking	MFO	8,626	01/09/1992	31/08/2013	0.0189	7.09	64.1	-	-	-
11 Tawau GT2	4	NSLA	Peaking	MFO	8,626	01/09/1994	31/08/2023	0.0189	7.09	64.1	-	-	0.23
12 Batu Sapi DG7	3	NSLA	Peaking	Diesel	11,242	01/09/1982	31/08/2012	0.0227	7.09	64.1	-	-	0.03
13 Batu Sapi DG8	5	NSLA	Base	Diesel	11,242	01/09/1991	31/08/2013	0.0227	7.09	64.1	-	-	-
14 Batu Sapi DG9	6	NSLA	Base	Diesel	11,242	01/09/1994	31/08/2014	0.0185	7.09	64.1	-	-	0.03
15 Batu Sapi DG10	6	NSLA	Peaking	Diesel	11,242	01/09/1991	31/08/2013	0.0227	7.09	64.1	-	-	-
16 Batu Sapi DG11	6	NSLA	Base	Diesel	11,242	01/09/1994	31/08/2013	0.0227	7.09	64.1	-	-	-
17 Gantisan Barge GTB	36	NSLA	Base	Diesel	12,837	01/09/1996	31/08/2014	0.0227	7.09	64.1	-	-	0.20
18 Labuk DG	8	NSLA	Base	MFO	7,805	01/09/1997	31/08/2013	0.0227	7.09	64.1	-	-	-
19 Sandakan GT Diesel	18	NSLA	Base	Diesel	11,242	01/05/2013	30/04/2025	0.0600	7.09	64.1	-	-	1.19
20 SESB Minor S. Grid DG	26	NSLA	Base	Diesel	10,789	01/09/1990	31/08/2014	0.0186	7.09	64.1	-	-	0.14
21 SESB Minor S. Non Grid DG	16	NSLA	Base	Diesel	11,586	01/09/1998	31/08/2019	0.0293	7.09	64.1	-	-	0.53
22 west SESB M/Hydro	2	NSLA	Mid	Hydro	-	01/09/1991	31/08/2021	0.0025	7.09	64.1	-	-	0.07
23 east Kudolia	64	SLA	Peaking	Diesel	13,043	15/04/2013	14/04/2019	0.0318	6.89	63.3	-	-	-
24 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-
25 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-
26 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-
27 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-
28 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-
29 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-
30 New	-	-	Input plant type	Input fuel type	-	-	-	-	-	-	-	-	-

Single Buyer Generation Inputs

IPP Information

IPP General Information

	Name	Capacity (MW)	Type (Base, Mid, peaking)	Fuel	Average net heat rate	PPA/SLA Start date	PPA/SLA end date	VOM RM/kWh	FOR	CRF - Tier 1	CRF - Tier 2 (No. of Yrs)	CRF - Tier 1	CRF - Tier 2
1	IPP Ruppolding CC	195	Base	Gas W	8,072	40,663	48,325	0	6	37	12	37	24
2	IPP SBFC Gas	100	Base	Gas W	8,861	39,673	47,269	0	5	60	12	60	50
3	IPP Tshik Shitut Gas	190	Base	Gas W	9,004	39,746	47,417	0	14	39	15	39	9
4	IPP ARU MFO	44	Mid	MFO	8,638	38,003	42,978	0	15	64	12	64	39
5	IPP Simuhung MFO	36	Mid	MFO	8,190	36,401	43,072	0	15	64	12	64	37
6	IPP SPC MFO	32	Base	MFO	8,190	36,166	41,152	0	15	48	12	48	27
7	IPP Likaran MFO	15	Peaking	MFO	8,047	36,134	43,830	0	14	48	12	48	27
8	IPP Sulara H, DG	34	Base	Diesel	10,204	36,100	41,892	0	35				
9	IPP SPR Energy Gas	100	Peaking	Gas W	8,938	41,978	49,247	0	6	56	12	56	28
10	IPP Kimanis Gas	285	Base	Gas W	7,841	41,730	49,399	0	6	53	15	53	32
11	est. CC10		Base	Gas E	7,840	45,745	53,414	0	7	52	15	52	39
12	SREP Kudatman Hydro	2	Base	SREP	40,026	47,726		0					
13	SREP P. Inguluan Hydro	5	Base	SREP	40,188	46,091		0					
14	SREP TSH BioEnergy	10	Base	SREP	39,400	45,900		0					
15	SREP Siharor BioEnergy	10	Base	SREP	39,903	47,573		0					
16	SREP Kinabio Power	10	Mid	SREP	39,839	47,509		0					
17	East Aero B. Supl. Diesel	60	Base	Diesel	10,270	43,344	43,708	0	6	53	15	53	32
18	East Aero L. Data	30	Peaking	Diesel	10,270	42,767	50,436	0	7	52	15	52	39
19	est. Aero B. Supl. Gas	60	Base	Gas W	10,270	43,708	51,012	0	7	52	15	52	39
20	West CC100 (NPSE Model)	300	Base	Gas W	7,817	47,598	55,257	0	5	56	12	56	28
21	est. Teck Gun.	10	Base	SREP	41,361	49,187		0					
22	ECO-Biohmas	3	Base	SREP	41,883	46,030		0					
23	Cahaya BumiJasa	10	Base	SREP	42,614	50,283		0					
24	East OEG (Our Energy Group)	4	Mid	SREP	42,702	50,371		0					
25	East OEG (Our Energy Group)	2	Mid	SREP	41,665	49,334		0					
26	East DL Biogas	2	Mid	SREP	42,029	49,698		0					
27	Est. TSH Biogas	3	Base	SREP	42,030	49,698		0					
28	est. OCB0	3	Base	Gas E	7,841	53,414	61,083	0	5	56	12	56	28
29	est CC100 (NPSE)	300	Base	Gas E	7,841	43,481	51,160	0	5	56	12	56	28
30	west CC10	100	Base	Gas W	7,841	43,683	53,352	0	5	56	12	56	28

Base year cost payment	Forecast Variable cost:						Forecast Variable Cost:						Regulatory Period - forecast variable cost:					
	Year 1 total		Year 2 total		Year 3 total		Year 4 total		Year 5 total		Year 6 total		Year 7 total		Year 8 total			
	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2016	31/08/2017	1/09/2017	31/08/2018	1/09/2018	31/08/2019	1/09/2019	31/08/2020	1/09/2020	31/08/2021	1/09/2021	31/08/2022		
1 IPP Bujading CC																		
2 IPP SEPC Gas																		
3 IPP Teluk Sait Gas																		
4 IPP ARL MFO																		
5 IPP Senudong MFO																		
6 IPP SPC MFO																		
7 IPP Libaran MFO																		
8 IPP Sulara H. DG																		
9 IPP SPR Energy Gas																		
10 IPP Kimanis Gas																		
11 east CC10																		
12 SREP Karamatan Hydro																		
13 SREP Pangapayan Hydro																		
14 SREP TSH BioEnergy																		
15 SREP Seguntor BioEnergy																		
16 SREP Kinabalu Power																		
17 East Aero B. Sapl. Diesel																		
18 East Aero L. Datu																		
19 east Aero B. Sapl. gas																		
20 west CC100 (KPSE Model)																		
21 Cash Horse																		
22 east Teck Guan																		
23 ECO-Biomass																		
24 Cahaya Bumijasa																		
25 East OEG (Our Energy Group)																		
26 East QL Blogas																		
27 East TSH Blogas																		
28 east OC60																		
29 east CC100 (KPSE)																		
30 west CC10																		

	Base year dispatch (MWh)		Forecast Dispatch (MWh)				Total Reg. Period - Forecast Dispatch				Forecast Dispatch (MWh)				
	1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2016	31/08/2017	1/09/2017	31/08/2018	1/09/2018	31/08/2019	1/09/2019	31/08/2020	Total
	28/02/2014	28/02/2015	28/02/2016	28/02/2017	28/02/2018	28/02/2019	28/02/2020	28/02/2021	28/02/2022	28/02/2023	28/02/2024	28/02/2025	28/02/2026	28/02/2027	Total
1 Patau Patou OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Patau Patou CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Melava DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Melava GTM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Pangl Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Upper Padas Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Lwagu Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Mini Hydro East	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Tawau DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Tawau GT1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Tawau GT2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Batu Sapi DG7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Batu Sapi DG8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Batu Sapi DG9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Batu Sapi DG10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Batu Sapi DG11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Ganfisan Barge GTB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Labuk DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 Sandakan GT Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 SESB Minor S. Grid DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 SESB Minor S. Non Grid DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22 west SESB M Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 east Kubota	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

SESB Generation Capacity Payment (RM) - (CRF and FOR)

	Base year capacity payment		Forecast capacity payment				Total Reg. Period - Forecast Capacity Cost				Regulatory Period - Forecast capacity payment				
	1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2016	31/08/2017	1/09/2017	31/08/2018	1/09/2018	31/08/2019	1/09/2019	31/08/2020	Total
	28/02/2014	28/02/2015	28/02/2016	28/02/2017	28/02/2018	28/02/2019	28/02/2020	28/02/2021	28/02/2022	28/02/2023	28/02/2024	28/02/2025	28/02/2026	28/02/2027	Total
1 Patau Patou OCGT	20,397,329	16,026,230	11,531,014	24,883,292	137,632	1,131,014	1,131,014	1,131,014	1,131,014	1,131,014	1,131,014	1,131,014	1,131,014	1,131,014	1,131,014
2 Patau Patou CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Melava DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Melava GTM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Pangl Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Upper Padas Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Lwagu Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Mini Hydro East	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Tawau DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Tawau GT1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Tawau GT2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Batu Sapi DG7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Batu Sapi DG8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Batu Sapi DG9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Batu Sapi DG10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Batu Sapi DG11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Ganfisan Barge GTB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Labuk DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 Sandakan GT Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 SESB Minor S. Grid DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 SESB Minor S. Non Grid DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22 west SESB M Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 east Kubota	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 New	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Summary of Gas and Coal Commodity Price Assumptions

	Base		Forecast				Total Reg. Period - Forecast Commodity Price				Regulatory Period - forecast commodity price				Total	
	31/08/2014	31/08/2015	31/08/2015	31/08/2015	31/08/2016	31/08/2016	31/08/2017	31/08/2017	31/08/2017	31/08/2018	31/08/2018	31/08/2019	31/08/2019	31/08/2020		31/08/2020
	1/09/2014	1/09/2015	1/09/2015	1/09/2016	1/09/2016	1/09/2017	1/09/2017	1/09/2018	1/09/2018	1/09/2019	1/09/2019	1/09/2020	1/09/2020	1/09/2020		1/09/2020
IPP Fuel Commodity Price Assumptions																
Gas W Dispatch Cost																
Gas E Dispatch Cost																
MFO Dispatch Cost																
Diesel Dispatch Cost																
SREP Dispatch Cost																
SESB Generation Fuel Commodity Price Assumptions																
Gas W Dispatch Cost																
Gas E Dispatch Cost																
MFO Dispatch Cost																
Distillate Dispatch Cost																
Hydro Dispatch																
Total (IPP plus SESB Generation)																
Total gas W Dispatch																
Total gas E Dispatch																
Total MFO Dispatch																
Total Diesel Dispatch																
Total SREP Dispatch																
Total Distillate Dispatch																
Total Hydro Dispatch																

SESB Revenue Requirement Model - Post Tax Nominal

Demand and Summary Single Buyer Generation Costs

Demand

Demand Forecast Losses	Start Date	End Date	Base		Forecast		Trial Reg. Prd Forecast		Regulatory Period - Forecast	
			1/09/2013	31/08/2014	1/09/2015	31/08/2016	1/09/2017	31/08/2018	1/09/2019	31/08/2020
SESB Generation Dispatch										
IPP Dispatch										
Total Dispatch										
Check			OK	OK	OK	OK	OK	OK	OK	OK

12%

Single Buyer Generation Cost for SESB Generation

Capacity Payment and Fixed O&M	Start Date	End Date	Base		Forecast		Trial Reg. Prd Forecast		Regulatory Period - Forecast	
			1/09/2013	31/08/2014	1/09/2015	31/08/2016	1/09/2017	31/08/2018	1/09/2019	31/08/2020
Variable Cost										
Fuel Cost										

Fuel Cost Breakdown

Gas										
MFO										
Distillate										
Other										

Single Buyer Generation Cost for IPPs

Capacity Payment and Fixed O&M	Start Date	End Date	Base		Regulatory Period - Forecast		Trial Reg. Prd Forecast		Regulatory Period - Forecast	
			1/09/2013	31/08/2014	1/09/2015	31/08/2016	1/09/2017	31/08/2018	1/09/2019	31/08/2020
Variable Cost - Incl SREP										
Fuel Cost										

Fuel Cost Breakdown

Gas										
MFO										
Distillate										
Other (RE)										

SESB Revenue Requirement Model - Post Tax Nominal

Regulatory Asset Base Inputs for SESB Generation (RM)

SESB Generation Regulatory Asset Base Inputs

Opening Regulatory Asset Base (RAB) for Base Year - SESB Generation

Generation Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1. Freehold Land		-	
2. Short Leasehold Land		-	
3. Long Leasehold Land		-	
4. Buildings & Civil Works		-	
5. Plant & Machinery		-	
6. Mains and Lines		-	
7. Distribution Services		-	
8. Meters		-	
9. Public Lighting		-	
10. Furniture and Fittings		-	
11. Motor Vehicles		-	
12. Name of Asset 12		-	
13. Name of Asset 13		-	
	0		

Depreciation Schedule Opening RAB - SESB Generation

	Start Date		Base - Actual		Forecast		Trial Reg. Prd.		Regulatory Period							
	Start Date	End Date	1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2016	31/08/2017	1/09/2017	31/08/2018	1/09/2018	31/08/2019	1/09/2019	31/08/2020
1. Freehold Land																
2. Short Leasehold Land																
3. Long Leasehold Land																
4. Buildings & Civil Works																
5. Plant & Machinery																
6. Mains and Lines																
7. Distribution Services																
8. Meters																
9. Public Lighting																
10. Furniture and Fittings																
11. Motor Vehicles																
12. Name of Asset 12																
13. Name of Asset 13																

Forecast Capex - SESB Generation

Start Date End Date	Base - Actual 1/09/2013 31/08/2014	Forecast			Trial Reg Prd 1/09/2016 31/08/2017	Regulatory Period						
		1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017		1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020				
1 Freehold Land												
2 Short Leasehold Land												
3 Long Leasehold Land												
4 Buildings & Civil Works												
5 Plant & Machinery												
6 Mains and Lines												
7 Distribution Services												
8 Meters												
9 Public Lighting												
10 Furniture and Fittings												
11 Motor Vehicles												
12 Name of Asset 12												
13 Name of Asset 13												
		0	0	0	0	0	0	0	0	0	0	0

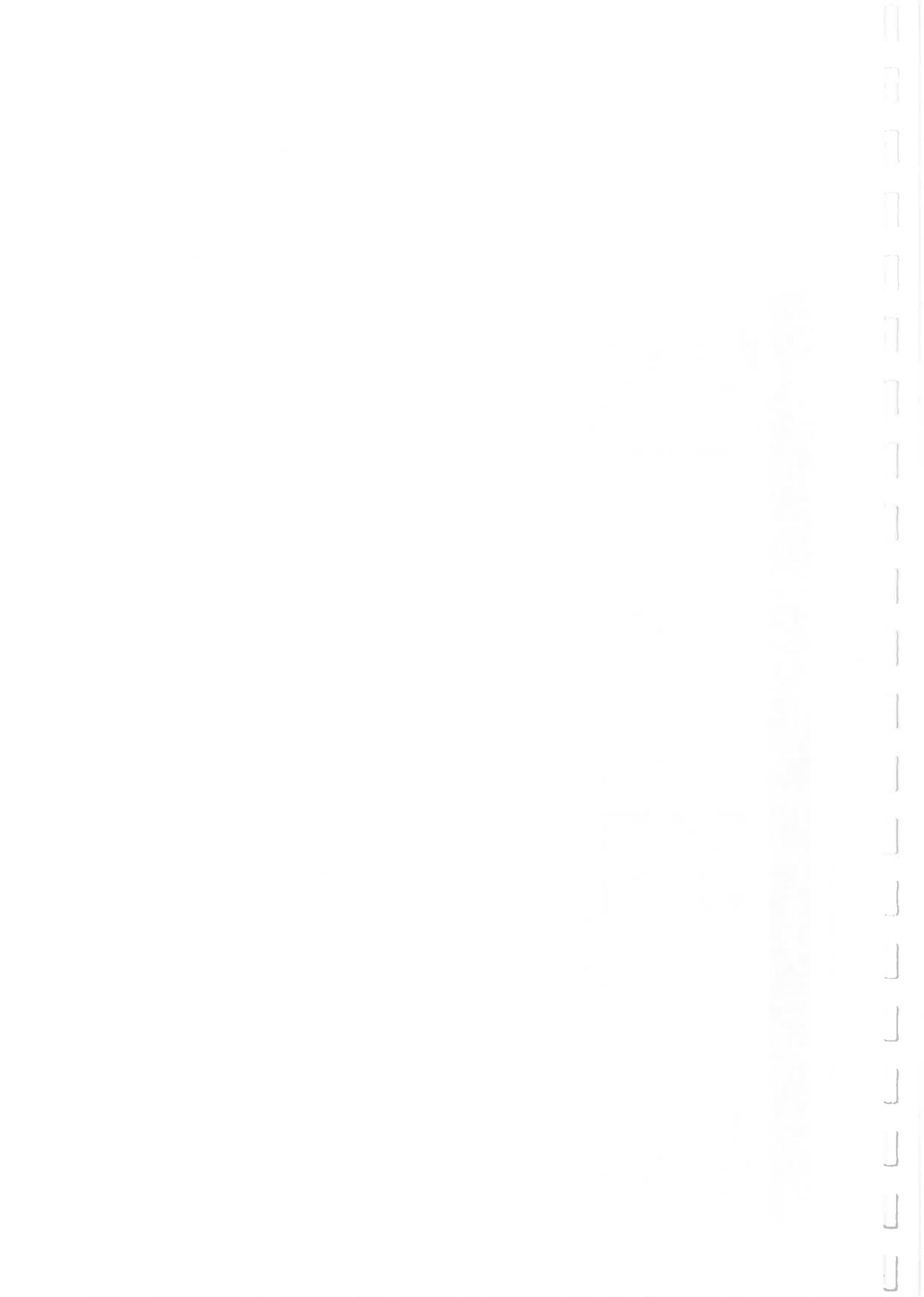
Capital Allowances Inputs: SESB Generation

Base Written Down Tax Asset Value : SESB Generation

Generation Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1 (1A+AA)	Capital Allowances for New Assets Year 2+ (AA)
1 Freehold Land				
2 Short Leasehold Land				
3 Long Leasehold Land				
4 Buildings & Civil Works				
5 Plant & Machinery				
6 Mains and Lines				
7 Distribution Services				
8 Meters				
9 Public Lighting				
10 Furniture and Fittings				
11 Motor Vehicles				
12 Name of Asset 12				
13 Name of Asset 13				
	0			

Forecast Capital Allowances on Existing Written Down Tax Asset: SESB Generation

Start Date End Date	Base - Actual		Forecast		Trial Reg Prd		Regulatory Period	
	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	
1 Freehold Land								
2 Short Leasehold Land								
3 Long Leasehold Land								
4 Buildings & Civil Works								
5 Plant & Machinery								
6 Mains and Lines								
7 Distribution Services								
8 Meters								
9 Public Lighting								
10 Furniture and Fittings								
11 Motor Vehicles								
12 Name of Asset 12								
13 Name of Asset 13								
	0	0	0	0	0	0	0	



SESb Revenue Requirement Model - Post Tax Nominal

Regulatory Asset Base Inputs (RM)

Transmission Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Transmission

Transmission Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1 Freehold Land			
2 Short Leasehold Land			
3 Long Leasehold Land			
4 Buildings & Civil Works			
5 Plant & Machinery			
6 Mains and Lines			
7 Distribution Services			
8 Meters			
9 Public Lighting			
10 Furniture and Fittings			
11 Motor Vehicles			
12 Name of Asset 12			
13 Name of Asset 13			
Total			

Depreciation Schedule Opening Regulatory Asset Base - Transmission

	Start Date		Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast	
	End Date	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020		
1 Freehold Land										
2 Short Leasehold Land										
3 Long Leasehold Land										
4 Buildings & Civil Works										
5 Plant & Machinery										
6 Mains and Lines										
7 Distribution Services										
8 Meters										
9 Public Lighting										
10 Furniture and Fittings										
11 Motor Vehicles										
12 Name of Asset 12										
13 Name of Asset 13										
Total			0	0	0	0	0	0	0	0

Forecast Capex - Transmission

	Start Date End Date	Base		Forecast		Trial Reg. Prd. 1/09/2016 31/08/2017	Regulatory Period - Forecast			
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2017 31/08/2018		1/09/2018 31/08/2019	1/09/2019 31/08/2020		
1 Freehold Land										
2 Short Leasehold Land										
3 Long Leasehold Land										
4 Buildings & Civil Works										
5 Plant & Machinery										
6 Mains and Lines										
7 Distribution Services										
8 Meters										
9 Public Lighting										
10 Furniture and Fittings										
11 Motor Vehicles										
12 Name of Asset 12										
13 Name of Asset 13										
			0	0		0	0	0	0	0

Transmission System Operations Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Transmission System Ops

Transmission System Operations Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1 Freehold Land			
2 Short Leasehold Land			
3 Long Leasehold Land			
4 Buildings & Civil Works			
5 Plant & Machinery			
6 Mains and Lines			
7 Distribution Services			
8 Meters			
9 Public Lighting			
10 Furniture and Fittings			
11 Motor Vehicles			
12 Name of Asset 12			
13 Name of Asset 13			
Total			

Depreciation Schedule Opening Regulatory Asset Base - Transmission System Ops

	Start Date End Date	Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast					
		1/09/2013 31/08/2014	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2018 31/08/2019	1/09/2019 31/08/2020		
1 Freehold Land													
2 Short Leasehold Land													
3 Long Leasehold Land													
4 Buildings & Civil Works													
5 Plant & Machinery													
6 Mains and Lines													
7 Distribution Services													
8 Meters													
9 Public Lighting													
10 Furniture and Fittings													
11 Motor Vehicles													
12 Name of Asset 12													
13 Name of Asset 13													

Forecast Capex - Transmission System Ops

	Start Date End Date	Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast					
		1/09/2013 31/08/2014	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2018 31/08/2019	1/09/2019 31/08/2020		
1 Freehold Land													
2 Short Leasehold Land													
3 Long Leasehold Land													
4 Buildings & Civil Works													
5 Plant & Machinery													
6 Mains and Lines													
7 Distribution Services													
8 Meters													
9 Public Lighting													
10 Furniture and Fittings													
11 Motor Vehicles													
12 Name of Asset 12													
13 Name of Asset 13													

Single Buyer Operations Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Single Buyer Operations

Single Buyer Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1. Freehold Land			
2. Short Leasehold Land			
3. Long Leasehold Land			
4. Buildings & Civil Works			
5. Plant & Machinery			
6. Mains and Lines			
7. Distribution Services			
8. Meters			
9. Public Lighting			
10. Furniture and Fittings			
11. Motor Vehicles			
12. Name of Asset 12			
13. Name of Asset 13			
Total			

Depreciation Schedule Opening Regulatory Asset Base - Single Buyer Operations

	Start Date End Date	Base		Forecast		Total Reg. Prd		Regulatory Period - Forecast				
		1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2016	31/08/2017	1/09/2017	1/09/2018	1/09/2019
1. Freehold Land												
2. Short Leasehold Land												
3. Long Leasehold Land												
4. Buildings & Civil Works												
5. Plant & Machinery												
6. Mains and Lines												
7. Distribution Services												
8. Meters												
9. Public Lighting												
10. Furniture and Fittings												
11. Motor Vehicles												
12. Name of Asset 12												
13. Name of Asset 13												

Forecast Capex - Single Buyer Operations

	Start Date End Date	Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast		
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020		
1 Freehold Land										
2 Short Leasehold Land										
3 Long Leasehold Land										
4 Buildings & Civil Works										
5 Plant & Machinery										
6 Mains and Lines										
7 Distribution Services										
8 Meters										
9 Public Lighting										
10 Furniture and Fittings										
11 Motor Vehicles										
12 Name of Asset 12										
13 Name of Asset 13										

Customer Services Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year - Retail Operations

Retail Operations Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1 Freehold Land			
2 Short Leasehold Land			
3 Long Leasehold Land			
4 Buildings & Civil Works			
5 Plant & Machinery			
6 Mains and Lines			
7 Distribution Services			
8 Meters			
9 Public Lighting			
10 Furniture and Fittings			
11 Motor Vehicles			
12 Name of Asset 12			
13 Name of Asset 13	0		

Depreciation Schedule Opening Regulatory Asset Base - Retail Operations

	Start Date End Date	Base 1/09/2013 31/08/2014	Forecast		Trial Reg. Prd. 1/09/2016 31/08/2017	Regulatory Period - Forecast			
			1/09/2014 31/08/2015	1/09/2015 31/08/2016		1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	
1 Freehold Land									
2 Short Leasehold Land									
3 Long Leasehold Land									
4 Buildings & Civil Works									
5 Plant & Machinery									
6 Mains and Lines									
7 Distribution Services									
8 Meters									
9 Public Lighting									
10 Furniture and Fittings									
11 Motor Vehicles									
12 Name of Asset 12									
13 Name of Asset 13									

Forecast Capex - Retail Operations

	Start Date End Date	Base 1/09/2013 31/08/2014	Forecast		Trial Reg. Prd. 1/09/2016 31/08/2017	Regulatory Period - Forecast			
			1/09/2014 31/08/2015	1/09/2015 31/08/2016		1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	
1 Freehold Land									
2 Short Leasehold Land									
3 Long Leasehold Land									
4 Buildings & Civil Works									
5 Plant & Machinery									
6 Mains and Lines									
7 Distribution Services									
8 Meters									
9 Public Lighting									
10 Furniture and Fittings									
11 Motor Vehicles									
12 Name of Asset 12									
13 Name of Asset 13									

Opening Regulatory Asset Base for Base Year - Networks

Networks Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1 Freehold Land 2 Short Leasehold Land 3 Long Leasehold Land 4 Buildings & Civil Works 5 Plant & Machinery 6 Mains and Lines 7 Distribution Services 8 Meters 9 Public Lighting 10 Furniture and Fittings 11 Motor Vehicles 12 Name of Asset 12 13 Name of Asset 13	0		

Depreciation Schedule Opening Regulatory Asset Base - Networks

	Start Date		Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast					
	End Date		1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2017	31/08/2018	1/09/2018	31/08/2019	1/09/2019	31/08/2020
1 Freehold Land 2 Short Leasehold Land 3 Long Leasehold Land 4 Buildings & Civil Works 5 Plant & Machinery 6 Mains and Lines 7 Distribution Services 8 Meters 9 Public Lighting 10 Furniture and Fittings 11 Motor Vehicles 12 Name of Asset 12 13 Name of Asset 13														

Forecast Capex - Networks

	Start Date End Date	Base		Forecast		Trial Reg. Ptd. 1/09/2016 31/08/2017	Regulatory Period - Forecast		
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2017 31/08/2018		1/09/2018 31/08/2019	1/09/2019 31/08/2020	
1 Freehold Land 2 Short Leasehold Land 3 Long Leasehold Land 4 Buildings & Civil Works 5 Plant & Machinery 6 Mains and Lines 7 Distribution Services 8 Meters 9 Public Lighting 10 Furniture and Fittings 11 Motor Vehicles 12 Name of Asset 12 13 Name of Asset 13									

Opening Regulatory Asset Base for Base Year - Customer Service

Customer Service Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1 Freehold Land 2 Short Leasehold Land 3 Long Leasehold Land 4 Buildings & Civil Works 5 Plant & Machinery 6 Mains and Lines 7 Distribution Services 8 Meters 9 Public Lighting 10 Furniture and Fittings 11 Motor Vehicles 12 Name of Asset 12 13 Name of Asset 13			

Depreciation Schedule Opening Regulatory Asset Base - Customer Service

	Start Date End Date	Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast					
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	1/09/2019 31/08/2020	1/09/2019 31/08/2020	1/09/2019 31/08/2020		
1 Freehold Land													
2 Short Leasehold Land													
3 Long Leasehold Land													
4 Buildings & Civil Works													
5 Plant & Machinery													
6 Mains and Lines													
7 Distribution Services													
8 Meters													
9 Public Lighting													
10 Furniture and Fittings													
11 Motor Vehicles													
12 Name of Asset 12													
13 Name of Asset 13													

Forecast Capex - Customer Service

	Start Date End Date	Base		Forecast		Trial Reg. Prd.		Regulatory Period - Forecast					
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	1/09/2019 31/08/2020	1/09/2019 31/08/2020			
1 Freehold Land													
2 Short Leasehold Land													
3 Long Leasehold Land													
4 Buildings & Civil Works													
5 Plant & Machinery													
6 Mains and Lines													
7 Distribution Services													
8 Meters													
9 Public Lighting													
10 Furniture and Fittings													
11 Motor Vehicles													
12 Name of Asset 12													
13 Name of Asset 13													

Capital Allowances Inputs: Transmission

Base Written Down Tax Asset Value : Transmission

Transmission Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1 (A+AAA)	Capital Allowances for New Assets Year 2+ (AA)
1 Freehold Land				
2 Short Leasehold Land				
3 Long Leasehold Land				
4 Buildings & Civil Works				
5 Plant & Machinery				
6 Mains and Lines				
7 Distribution Services				
8 Meters				
9 Public Lighting				
10 Furniture and Fittings				
11 Motor Vehicles				
12 Name of Asset: 12				
13 Name of Asset: 13				

Forecast Capital Allowances on Existing Written Down Tax Asset

	Start Date End Dates	Base		Forecast		Total Reg. Prd.		Regulation Period - Forecast		
		1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2016	31/08/2017	1/09/2017	1/09/2018	1/09/2019
1 Freehold Land										
2 Short Leasehold Land										
3 Long Leasehold Land										
4 Buildings & Civil Works										
5 Plant & Machinery										
6 Mains and Lines										
7 Distribution Services										
8 Meters										
9 Public Lighting										
10 Furniture and Fittings										
11 Motor Vehicles										
12 Name of Asset: 12										
13 Name of Asset: 13										

Capital Allowances Inputs: Transmission System Operation

Base Written Down Tax Asset Value : Transmission System Ops

Transmission System Operations Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1 (A+AA)	Capital Allowances for New Assets Year 2+ (AA)
1 Freehold Land				
2 Short Leasehold Land				
3 Long Leasehold Land				
4 Buildings & Civil Works				
5 Plant & Machinery				
6 Mains and Lines				
7 Distribution Services				
8 Meters				
9 Public Lighting				
10 Furniture and Fittings				
11 Motor Vehicles				
12 Name of Asset 12				
13 Name of Asset 13				

Forecast Capital Allowances on Existing Written Down Tax Asset

	Start Date End Date	Base		Forecast		Regulatory Period - Forecast					
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020			
1 Freehold Land											
2 Short Leasehold Land											
3 Long Leasehold Land											
4 Buildings & Civil Works											
5 Plant & Machinery											
6 Mains and Lines											
7 Distribution Services											
8 Meters											
9 Public Lighting											
10 Furniture and Fittings											
11 Motor Vehicles											
12 Name of Asset 12											
13 Name of Asset 13											

Capital Allowances Inputs: Single Buyer Operations

Base Written Down Tax Asset Value : Single Buyer Operations

Single Buyer Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1 (A+AA)	Capital Allowances for New Assets Year 2+ (AA)
1 Freehold Land				
2 Short Leasehold Land				
3 Long Leasehold Land				
4 Buildings & Civil Works				
5 Plant & Machinery				
6 Mains and Lines				
7 Distribution Services				
8 Meters				
9 Public Lighting				
10 Furniture and Fittings				
11 Motor Vehicles				
12 Name of Asset 12				
13 Name of Asset 13				

Forecast Capital Allowances on Existing Written Down Tax Asset

1 Freehold Land 2 Short Leasehold Land 3 Long Leasehold Land 4 Buildings & Civil Works 5 Plant & Machinery 6 Mains and Lines 7 Distribution Services 8 Meters 9 Public Lighting 10 Furniture and Fittings 11 Motor Vehicles 12 Name of Asset 12 13 Name of Asset 13	Start Date End Date	Base		Forecast		Total Reg. Prid.	Regulatory Period - Forecast			
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017		1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	

Capital Allowances Inputs: Customer Services

Base Written Down Tax Asset Value : Customer Services

Customer Services Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1 (IA+AA)	Capital Allowances for New Assets Year 2+ (AA)
1 Freehold Land				
2 Short Leasehold Land				
3 Long Leasehold Land				
4 Buildings & Civil Works				
5 Plant & Machinery				
6 Mains and Lines				
7 Distribution Services				
8 Meters				
9 Public Lighting				
10 Furniture and Fittings				
11 Motor Vehicles				
12 Name of Asset 12				
13 Name of Asset 13				
Total				

Forecast Capital Allowances on Existing Written Down Tax Asset

Customer Services Asset Category	Start Date End Date	Base		Forecast		Regulatory Period - Forecast					
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020			
1 Freehold Land											
2 Short Leasehold Land											
3 Long Leasehold Land											
4 Buildings & Civil Works											
5 Plant & Machinery											
6 Mains and Lines											
7 Distribution Services											
8 Meters											
9 Public Lighting											
10 Furniture and Fittings											
11 Motor Vehicles											
12 Name of Asset 12											
13 Name of Asset 13											

SESB Revenue Requirement Model - Post Tax Nominal

Opex Inputs (RM)

Opex - Transmission

Transmission Opex Category	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast				
	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	1/09/2018 31/08/2019	1/09/2019 31/08/2020	1/09/2020 31/08/2021	
Repairs & Maintenance Staff Costs Other General Expenses (Exclude Depreciation)											
	0	0	0	0	0	0	0	0	0	0	0

Opex - System Operations

Transmission System Ops Opex Category	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast				
	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	1/09/2018 31/08/2019	1/09/2019 31/08/2020	1/09/2020 31/08/2021	
Repairs & Maintenance Staff Costs Other General Expenses (Exclude Depreciation)											
	0	0	0	0	0	0	0	0	0	0	0

Opex - Single Buyer Operations

Single Buyer Operations Opex Category	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast		
	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020		
Repairs & Maintenance Staff Costs Other General Expenses (Exclude Depreciation)	0	0	0	0	0	0	0	0	0

Opex - Customer Services

Customer Services Opex Category	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast		
	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020		
Repairs & Maintenance Staff Costs Other General Expenses (Exclude Depreciation) Cost of Sales Interest on customer deposit	0	0	0	0	0	0	0	0	0

Allocation Matrix

	Transmission	System operations	Single buyer ops	Customer Services	Total
Average RAB					0%
Depreciation					0%
Opex					0%
Capital Allowances					0%

	Base		Forecast		Tfml Reg Period		Regulatory Period - Forecast				
	01/12/1900	31/12/1900	31/12/1900	30/12/1901	31/12/1902	30/12/1903	31/12/1903	30/12/1904	31/12/1904	30/12/1905	31/12/1905
Working Capital Requirements											
Trade Receivables											
Electricity Debtors											
Strategic Spares											
Minimum Cash Requirement											
Trade Payables											
IPP (Cap Charge & Energy Charge)											
SLA (Cap Charge & Energy Charge)											
Net Working Capital (WC)											

Cash operating requirement = All cash operating requirement which includes: (a) Fuel cost (b) Purchase of power (c) Fixed and variable operating cost and (d) capital expenditure

SESB Revenue Requirement Model - Post Tax Nominal

Joint Costs Inputs (RM)

Joint Costs Regulatory Asset Base Inputs

Opening Regulatory Asset Base for Base Year

Other Asset Category	Accounting Written Down Value	Remaining Life	Asset Life (New Asset)
1 Freehold Land			
2 Short Leasehold Land			
3 Long Leasehold Land			
4 Buildings & Civil Works			
5 Plant & Machinery			
6 Mains and Lines			
7 Distribution Services			
8 Meters			
9 Public Lighting			
10 Furniture and Fittings			
11 Motor Vehicles			
12 Name of Asset 12			
13 Name of Asset 13			

Depreciation Schedule Opening Regulatory Asset Base

	Start Date		Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast						
	Start Date	End Date	1/09/2013	31/08/2014	1/09/2014	31/08/2015	1/09/2015	31/08/2016	1/09/2016	31/08/2017	1/09/2017	31/08/2018	1/09/2018	31/08/2019	1/09/2019
1 Freehold Land															
2 Short Leasehold Land															
3 Long Leasehold Land															
4 Buildings & Civil Works															
5 Plant & Machinery															
6 Mains and Lines															
7 Distribution Services															
8 Meters															
9 Public Lighting															
10 Furniture and Fittings															
11 Motor Vehicles															
12 Name of Asset 12															
13 Name of Asset 13															

Forecast Capex

Other Asset Category	Start Date End Date	Base		Forecast		Total Reg. Prd	Regulatory Period - Forecast			
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017		1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	
1 Freehold Land										
2 Short Leasehold Land										
3 Long Leasehold Land										
4 Buildings & Civil Works										
5 Plant & Machinery										
6 Mains and Lines										
7 Distribution Services										
8 Meters										
9 Public Lighting										
10 Furniture and Fittings										
11 Motor Vehicles										
12 Name of Asset 12										
13 Name of Asset 13										

Capital Allowances Inputs: Joint Costs

Base Written Down Tax Asset Value : Joint Costs

Other Asset Category	Base Written Down Tax Value	Tax Capital Allowances Rates for Existing Assets	Capital Allowances for New Assets Year 1	Capital Allowances for New Assets Year 2+
1 Freehold Land				
2 Short Leasehold Land				
3 Long Leasehold Land				
4 Buildings & Civil Works				
5 Plant & Machinery				
6 Mains and Lines				
7 Distribution Services				
8 Meters				
9 Public Lighting				
10 Furniture and Fittings				
11 Motor Vehicles				
12 Name of Asset 12				
13 Name of Asset 13				

Forecast Capital Allowances on Existing Written Down Tax Asset

	Start Date End Date	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast	
		1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	
1 Freehold Land									
2 Short Leasehold Land									
3 Long Leasehold Land									
4 Buildings & Civil Works									
5 Plant & Machinery									
6 Mains and Lines									
7 Distribution Services									
8 Meters									
9 Public Lighting									
10 Furniture and Fittings									
11 Motor Vehicles									
12 Name of Asset 12									
13 Name of Asset 13		0	0	0	0	0	0	0	0

Joint Costs Opex

Joint Opex Category	Base		Forecast		Trial Reg. Prd		Regulatory Period - Forecast	
	1/09/2013 31/08/2014	1/09/2014 31/08/2015	1/09/2015 31/08/2016	1/09/2016 31/08/2017	1/09/2017 31/08/2018	1/09/2018 31/08/2019	1/09/2019 31/08/2020	
Repairs & Maintenance								
Staff Costs								
Other General Expenses								
License Fees & Water Royalty								
	0	0	0	0	0	0	0	



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