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Consultant pool to provide strategic and operational support to the South African power sector reform

User Manual and Guide for Cost of Supply Model

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ABBREVIATIONS

AMEU	Association of Municipal Electricity Utilities
BAU	Business as usual
CAPEX	Capital Expenditure
COS	Cost of Supply / Cost of Service
CTS	Cost to Serve
	(The two above terms are utilised interchangeably throughout the report)
DMRE	Department of Mineral Resources and Energy
Eskom	Eskom Holdings SOC Limited, the South African national electricity utility
EV	Electric vehicles
FBE	Free basic electricity
FY	Financial Year
GB	Great Britain
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
HV	High Voltage
IPP	Independent Power Producer
KPIs	Key Performance Indicators
kVA	Kilovolt-amperes
kWh	Kilowatt hours
LV	Low voltage
MD	Maximum Demand
MV	Medium voltage
NDA	Non-Disclosure Agreement
NER Tariff Guideline	The 2004 NER National Retail Tariff Guideline
NERSA	National Energy Regulator of South Africa
NMD	Nominated Maximum Demand
NTL	Non-Technical Losses
OPEX	Operational Expenditure
P&L	Profit and Loss
POD	Point of Delivery
PPA	Power Purchase Agreement
PPT	PowerPoint Presentation
RE	Renewable Energy
ROR	Rate of Return
SAGEN	South African German Energy Programme
SALGA	South African Local Government Association

SEA	Sustainable Energy Africa
SSEG	Small Scale Embedded Generation
The Project	The consulting assignment outlined in the Terms of Reference
TL	Technical Losses
ToR	Terms of Reference
TOU	Time of use
UoS	Use of System
WACC	Weighted Average Cost of Capital
WG or Working Group	Working Group, consisting of representatives from inter alia National Treasury, the DMRE, NERSA, SALGA, AMEU and Eskom
WP	Work Package
O&M	Operation & Maintenance

1. INTRODUCTION

1.1 BACKGROUND

This user manual is a deliverable under the South African–German Energy Programme (SAGEN), funded by the German government and implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ). The DMRE, National Treasury, NERSA, SALGA, AMEU and Eskom are all partner organisations to SAGEN.

This user manual explains how to use the Cost-of-Service model built for municipalities to submit their tariffs revision to NERSA. As part of the project under SAGEN, WSP (formerly Ricardo) built **an expert version** of the model for large municipalities and **a simplified version** for smaller municipalities with less data. This user manual covers both versions of the model.

We first present the golden rules to use this model in both expert and simplified modes, along with key use cases for the user to follow to conduct the COS study.

1.2 COMPLIANCE WITH THE REGULATORY FRAMEWORK

This section sets out the basis on which the Cost of Supply tool complies with the NERSA Cost of Service Framework and aligns with the objectives of the Electricity Pricing Policy. It describes the model's structure, the sequence of calculations it performs, and the manner in which each step satisfies a specific regulatory requirement

1.2.1 Compliance with the NERSA Cost of Supply Framework

The tool has been designed around the five sequential modelling steps prescribed by the NERSA Cost of Service Framework. Each step depends on the outputs of the step preceding it, so that every result produced by the model can be traced back to an identified cost, a documented input, and a stated allocation rule. Compliance is therefore a function of the model's architecture rather than a matter of subsequent reconciliation.

1. **Revenue Requirement:** The first step determines the total revenue requirement, calculated separately for the Wires and the Retail business areas. Depending on the maturity of the available data, the revenue requirement is derived using either a Cost Plus or a Rate of Return methodology. This treatment gives effect to section 15(1)(a) of the Electricity Regulation Act 4 of 2006, which requires that the tariff methodology enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. In accordance with the principle of efficiency, the COS tool also allows the level of losses to be capped at an allowable level as determined by NERSA. This ensures that only an efficient level of losses is included in the revenue requirement.
2. **Cost Functionalisation:** The second step functionalises costs by assigning them to the main business areas. Costs functionalised to the Wires business area comprise

return on regulated asset base, depreciation on municipally funded infrastructure, network repairs and maintenance, and an allocated share of corporate and other operating expenditure. Costs functionalised to the Retail business area comprise wholesale bulk electricity purchases from Eskom and other third parties (inclusive of the cost of losses), other energy purchases, metering, billing and vending costs, and marketing and customer-related operating expenditure.

3. **Cost Classification:** The third step classifies the functionalised costs according to the cost driver categories recognised by NERSA, namely energy, demand and customer costs. This classification is the mechanism by which the results can be converted into a defensible tariff structure.
4. **Cost Allocation:** The fourth step allocates the classified costs to customer classes using load profiles, loss parameters, and customer weightings. The use of defined and documented allocation parameters satisfies the cost allocation requirements of the Framework.
5. **COS Results:** The fifth step produces cost-to-serve results by customer class that feed directly into rate design.

The separation of Wires and Retail before classification and allocation is the key compliance feature: it gives the regulator transparent cost attribution and allows each function to be scrutinised independently.

1.2.2 Compliance with the Electricity Pricing Policy

The same structure gives effect to the principal outcomes required of municipal tariffs by the Electricity Pricing Policy (EPP).

With regards to cost-reflectivity, tariffs produced by the model are derived from an allocated revenue requirement rather than from historic tariffs adjusted by a uniform increase. The resulting charges consequently reflect the cost actually incurred in serving each customer class, which is the central requirement of the EPP.

The classification of costs into energy, demand and customer cost drivers produces charges in the form considered by the EPP, namely an energy charge expressed in R/kWh, a demand charge expressed in R/kVA/month, and a fixed customer charge expressed in R/customer/month. Fixed costs are thereby recovered through fixed charges and variable costs through variable charges.

The establishment of a cost to serve for each customer class makes any cross-subsidy explicit and measurable. Subsidy policy options may accordingly be determined as a deliberate and informed decision rather than remaining embedded and non-transparent within the tariff.

In respect to efficiency and prudency, both the Cost Plus and the Rate of Return methodologies are applied against a defined set of verifiable data inputs, including asset registers, audited financial statements, customer billing data, Eskom invoices etc. The provision for the user to limit the allowable level of losses included in the revenue requirement support the policy position that only efficiently incurred costs be recovered from customers.

With respect to transparency and equitable treatment, the model relies on verifiable inputs, including D-form data, Eskom invoices, the trial balance, the asset register and load profiles, and applies a consistent method across all customer classes. This provides a uniform and replicable basis for regulatory scrutiny and supports the non-discriminatory treatment of customers in comparable circumstances

1.3 GOLDEN RULES

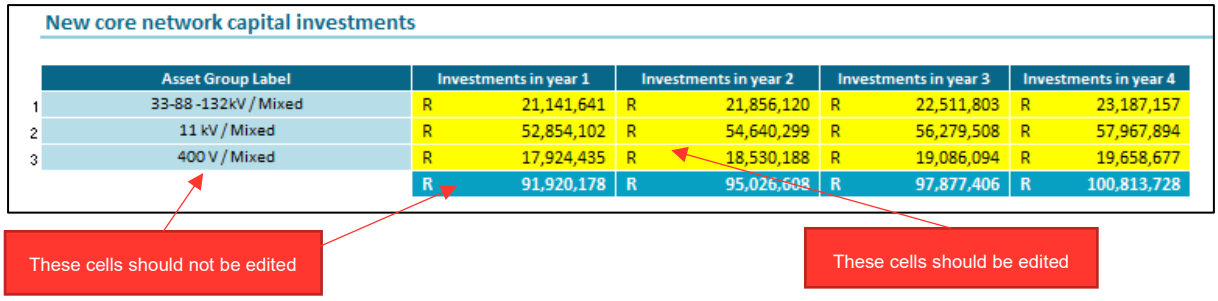
There are several golden rules to remember when configuring the model to get accurate results. Please make sure all the following rules are followed before analysing the COS results.

1.3.1 Review title map guide sheet

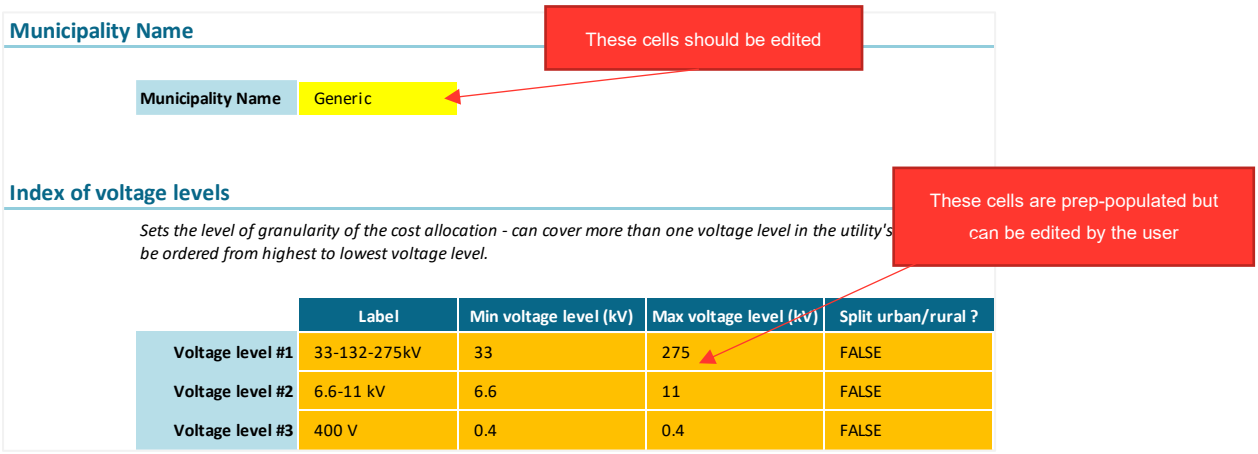
The first 3 sheets (Title, Map, Guide) of the model are introductory sheets that help the user understand the structure of the model. Please read the content of these sheets before adding your inputs.

1.3.2 Navigating the model

In the expert version, only yellow cells should and can be edited with inputs. All other cells should not be replaced with any hard-coded values of text. An example of this is illustrated below:



In the simplified version of the model, in addition to the yellow cells which require inputs from the user, some cells will be pre-populated in orange which can be edited by the user if data is available. The aim of the pre-populated cells is to simplify the model for smaller municipalities that have access to less data.

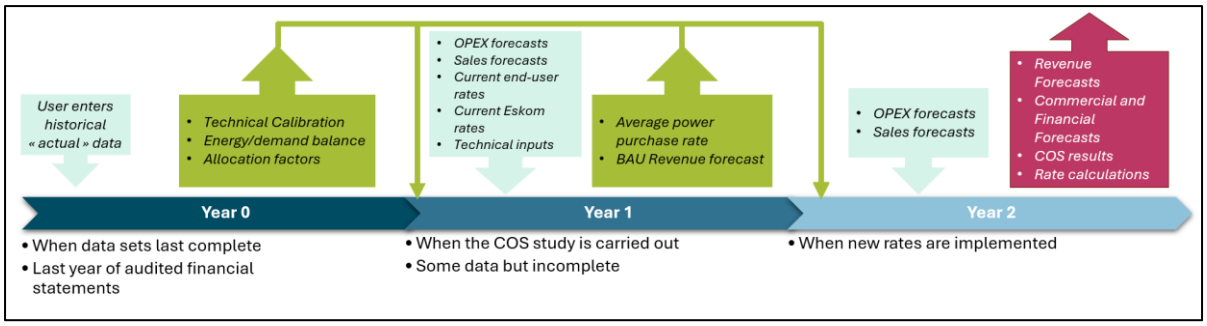


1.3.3 Multi-year analysis

The model includes a multi-year analysis where the user must input historical data, the current year's data and forecasted data. The model is built to compute the tariffs for the next financial year.

The figure below illustrates how the model is structured in a manner that incorporates a multi-year perspective concerning data and calculations. This also further highlights the convention utilized in naming the various financial periods.

Figure 1: Visual illustration of the multi-year nature of V2 of the standardised model



1.3.4 Data quality diagnostic

The data quality diagnostic sheet enables the user to ensure all the inputs and COS results are accurate. The data quality diagnostic feature is only added to specific sheets, namely:

1. Index tables
2. Eskom Ppurchase Vol Inp (Year 0)
3. Commercial Inputs (Year 0)
4. Commercial Inputs (Years 1-4)
5. Technical Inputs (Years 1-4)
6. End-User Tariff Inputs (Year 1)
7. Power Purchase Inputs Summary

Please make sure that all the sheets have “check” if they have “Add Input” or “Error”, please refer to the specific sheet and add inputs or more accurate inputs.

2. USE CASES

2.1 INTRODUCTION

This section provides step-by-step guidance for a selection of typical use cases for this model.

The use cases considered are as follows:

- **USE CASE 1: Conducting a COS Study –** the model is used to capture historical data and methodological assumptions thereby conducting a COS study
- **USE CASE 2: Validating inputs & Navigating COS Study Results –** the model is used to review the quality of inputs and present graphic representations of the COS results
- **USE CASE 3: Design & Calculate End-User Rates –** the model is used to view a dashboard containing information on COS results and how to design rates
- **USE CASE 4: Rate Impact Analysis –** the model is used to observe the impact of changes made to customer rates across average load and consumption
- **USE CASE 5: Conducting a COS Study (Simplified version) –** the model is used to capture historical data and methodological assumptions thereby conducting a COS study with some pre-populated inputs (this Use Case is included in Appendix 3.1)

The following sections should be read alongside the *golden rules* as highlighted in Section 1.3.

2.2 USE CASE 1: CONDUCTING A DETAILED COS STUDY WITH THE EXPERT VERSION

The model's objective is to conduct a COS study. The user needs to input the pertinent information required to conduct a COS study. Under each step of this use case, a specific worksheet is discussed. The result of Use Case 1 will be a COS analysis specific to the municipality based on the data provided. Unpacking results will be outlined in Use Cases 2-4.

2.2.1 Data requirements and implications of using expert mode

Where the required data is available, it is ideal for the user to undertake the COS study using the expert mode of the tool. Expert mode gives the user access to the full set of model features and allows the user to input more granular information across the technical, financial and commercial components of the utility. This reduces the extent to which the model must rely on simplified assumptions or pre-populated values and, consequently, improves the accuracy and traceability of the calculation outputs. The resulting COS results are therefore more likely to reflect the true cost to serve each customer category.

The main requirement for using expert mode is that the user must have a sufficiently detailed understanding of both the tool and the utility's underlying data. The user should understand how the model uses each input in the revenue requirement, functionalisation, classification, allocation and tariff design stages, and should be able to identify the appropriate data source for each input. Expert mode is therefore best suited to users who are familiar with the municipality's financial statements, budgets, electricity purchases, network configuration, customer base, loss position and tariff structures.

Use of expert mode also implies a higher level of data granularity. The typical data requirements include a reduced network diagram; audited financial statements; approved budgets for the relevant successive years; asset register; capital network investment plans; load profile data for each customer category; customer billing data; current and forecast sales and customer numbers; current end-user tariff schedules; information on technical and non-technical losses at the different voltage levels; an understanding of which customer categories or areas contribute materially to non-technical losses; Eskom bills; Eskom's current

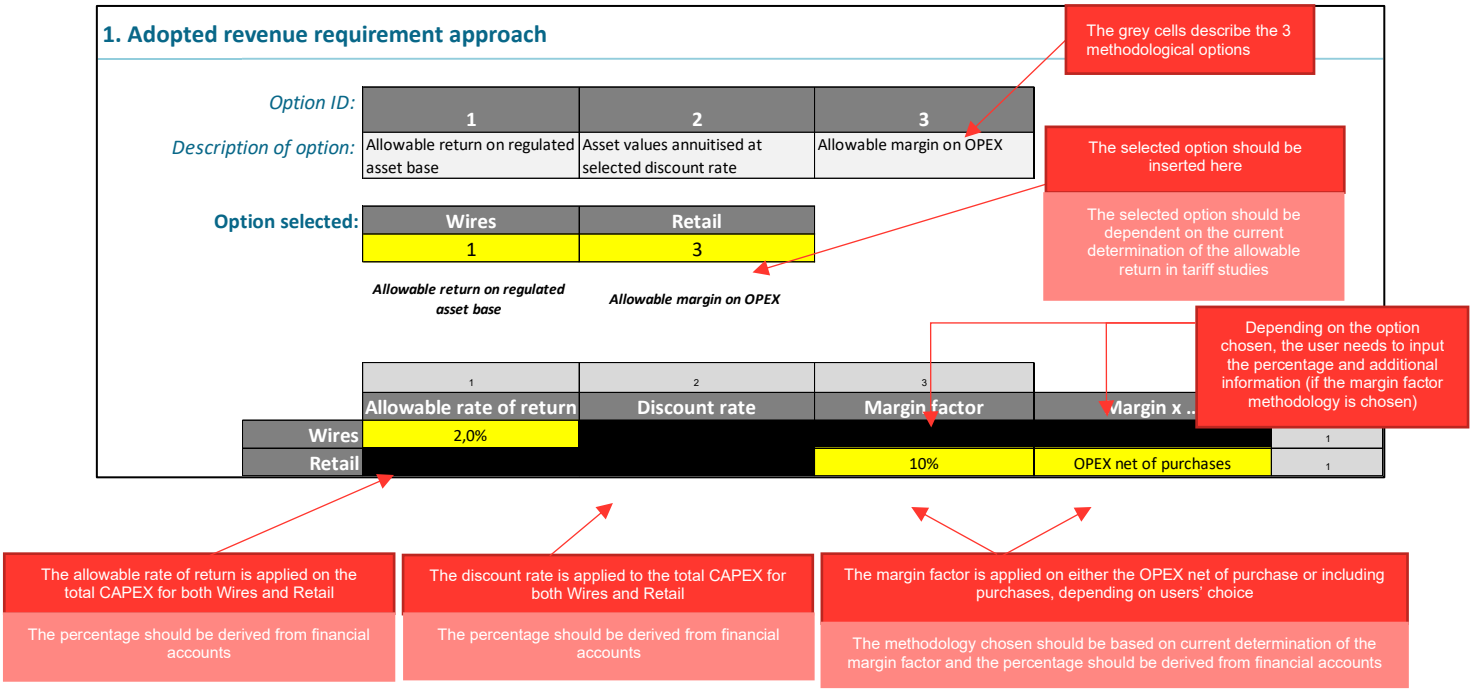
tariffs and expected tariff increases; and billing data for other energy purchases, including power purchases from non-Eskom sources where applicable.

The implication of these requirements is that expert mode may require more time and effort to complete than the simplified version, particularly where data is stored across different municipal departments or must be reconciled before it can be input into the model. However, this additional effort improves the robustness of the COS study. Better quality and more granular input data reduces the need for assumptions, improves the allocation of costs between voltage levels and customer categories, and provides a stronger basis for explaining the results to internal stakeholders, customers and the regulator.

2.2.2 Input on the "Methodology Inputs" sheet

What is required from the user in this step is to complete the choices provided in the "*Methodology inputs*" worksheet. The user should pay careful attention to the options selected as these inputs define what data the user must input and which methodologies are used throughout the model. The figures below describe each input and where the user can source the information.

The **"*Adopted revenue requirement approach*"** allows the user to decide the methodology to compute the allowed return included in the revenue requirement. This is calculated separately for each business area: Wires and Retail.



Methodology note: Selecting the revenue requirement approach

The user must select the approach used to determine the return, margin or capital recovery component of the revenue requirement for each business area. The available options are: an allowable return on the regulated asset base, asset values annuitised at a selected discount rate, and an allowable margin on OPEX. As described in Section 1.2.1, this functionality allows the tool to support both Rate of Return and Cost Plus approaches, depending on the availability and quality of the municipality's data.

a) Under the **allowable return on the regulated asset base** approach, the model applies a Rate of Return methodology. This approach is typically used where the utility has a reasonably complete and up-to-date asset register, allowing the regulated asset base to be determined. The allowable return is calculated by applying an appropriate rate of return, normally linked to the utility's weighted average cost of capital, to the applicable regulated asset base. This approach is more data-intensive but provides a stronger basis for linking the revenue

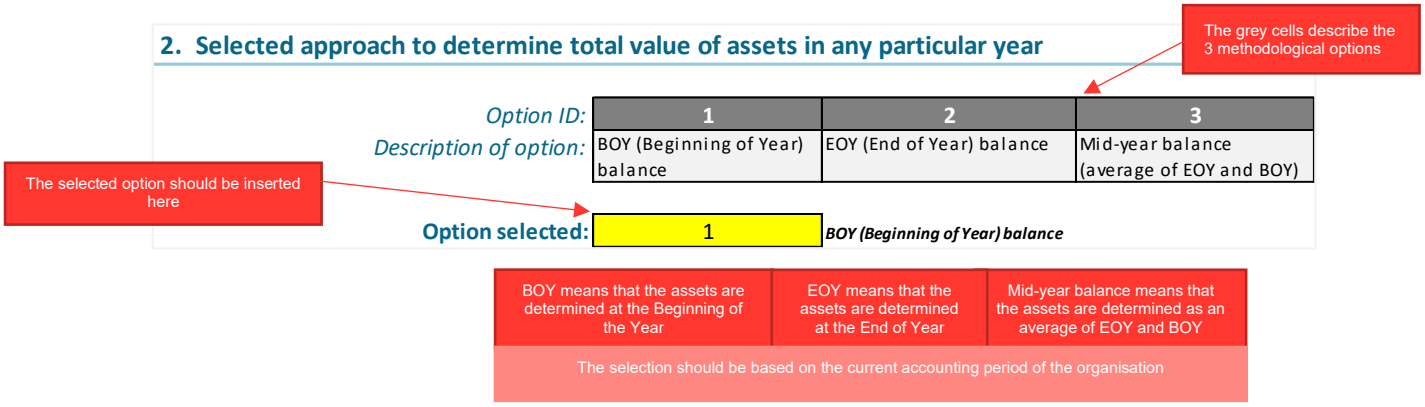
requirement to the capital invested in the network and retail assets. Further detail on the asset register inputs is provided in Section 2.2.6.

b) The **asset values annuitised at selected discount rate** approach provides an alternative way of converting asset values into an annual capital-related cost. Under this method, the value of the relevant assets is annualised over an assumed asset life using the selected discount rate. The resulting annual amount represents the levelised yearly charge required to recover the asset value, together with the financing cost implied by the discount rate, over the assumed period. This approach may be useful where the user has asset values available but does not have sufficient information to calculate a full regulated asset base, depreciation allowance and weighted average cost of capital separately. The selected discount rate should therefore be chosen carefully, as it affects the annualised cost included in the revenue requirement.

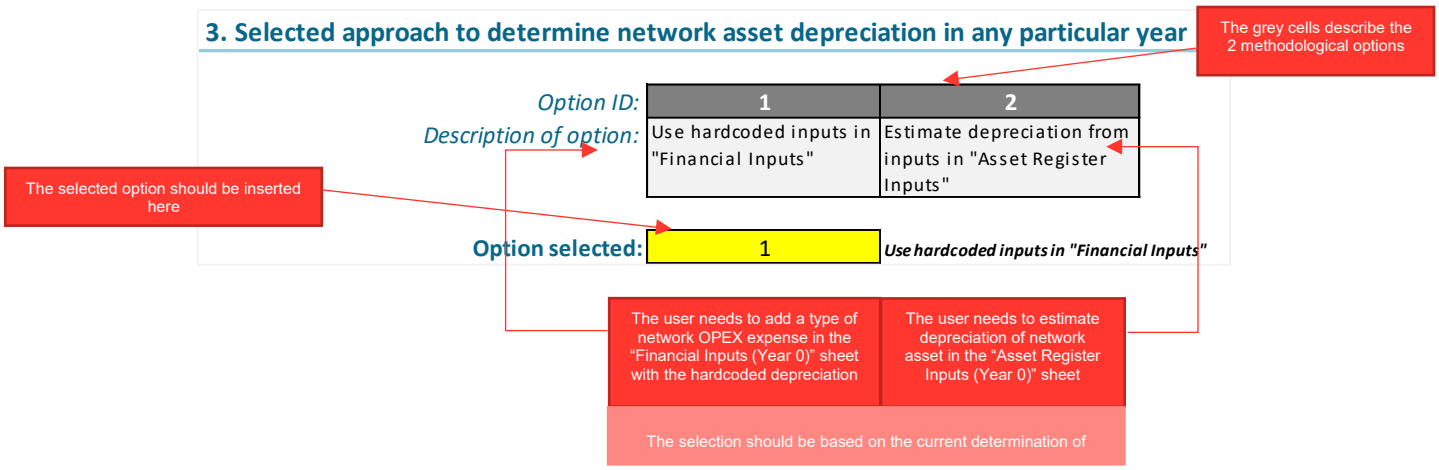
c) The **allowable margin on OPEX** approach is consistent with a Cost Plus methodology. Under this approach, the model determines the revenue requirement by allowing the recovery of operating expenditure plus an allowable margin. Depending on the selected option, the margin may be applied either to OPEX excluding electricity purchases or to OPEX including electricity purchases. In line with the COS Framework, the allowable margin may be between 10% and 20%. This approach is less data-intensive than a full Rate of Return approach, but it is also less directly linked to the value of assets used to provide the service.

The selected method affects the revenue requirement and therefore the resulting COS outputs. Users should select the method that best reflects the available data and should replace assumptions with municipality-specific data where possible.

The **"*Selected approach to determine total value of assets in any particular year*"** is for the user to select when the assets' value should be taken into account. This depends on when the entity is issuing its financial statement and the end of its fiscal year.

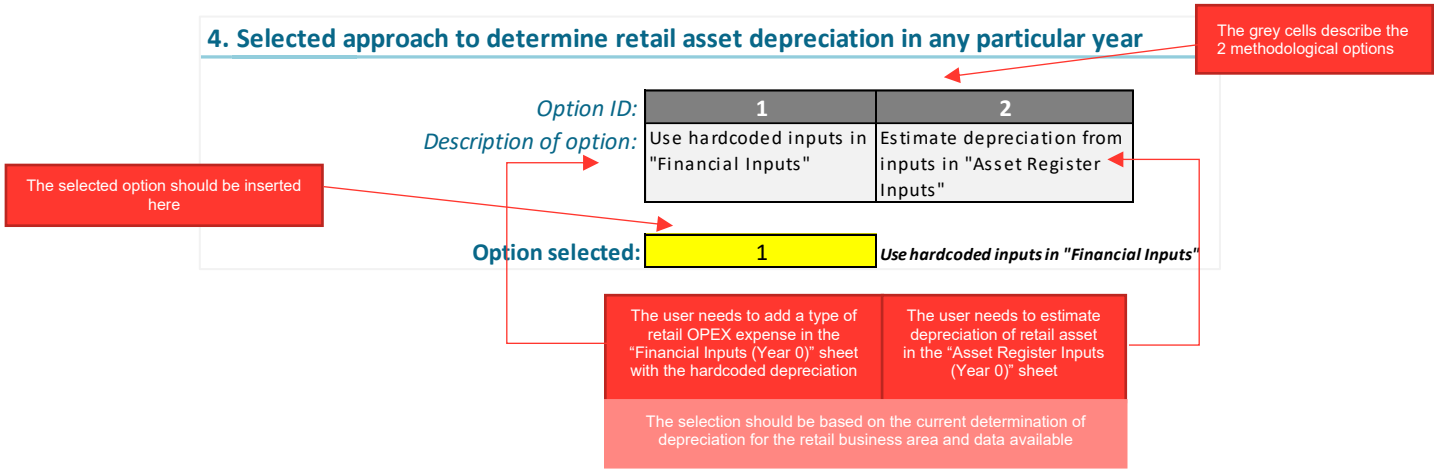


The **"*Selected approach to determine network asset depreciation in any particular year*"** is for the user to define the methodology to assess the depreciation of network assets.



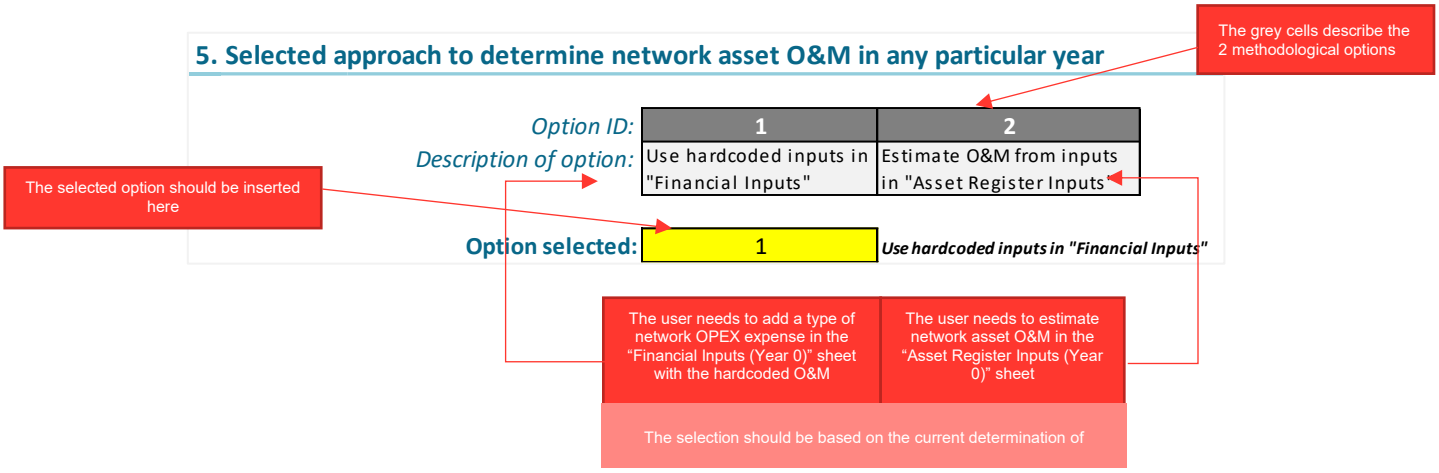
Note that if option 2 is selected, depreciation values related to network assets should **not** be entered in the Financial Inputs (Year 0) or Financial Inputs (Years 1-4) sheets.

The **"*Selected approach to determine retail asset depreciation in any particular year*"** is for the user to define the methodology to assess the depreciation of retail assets.



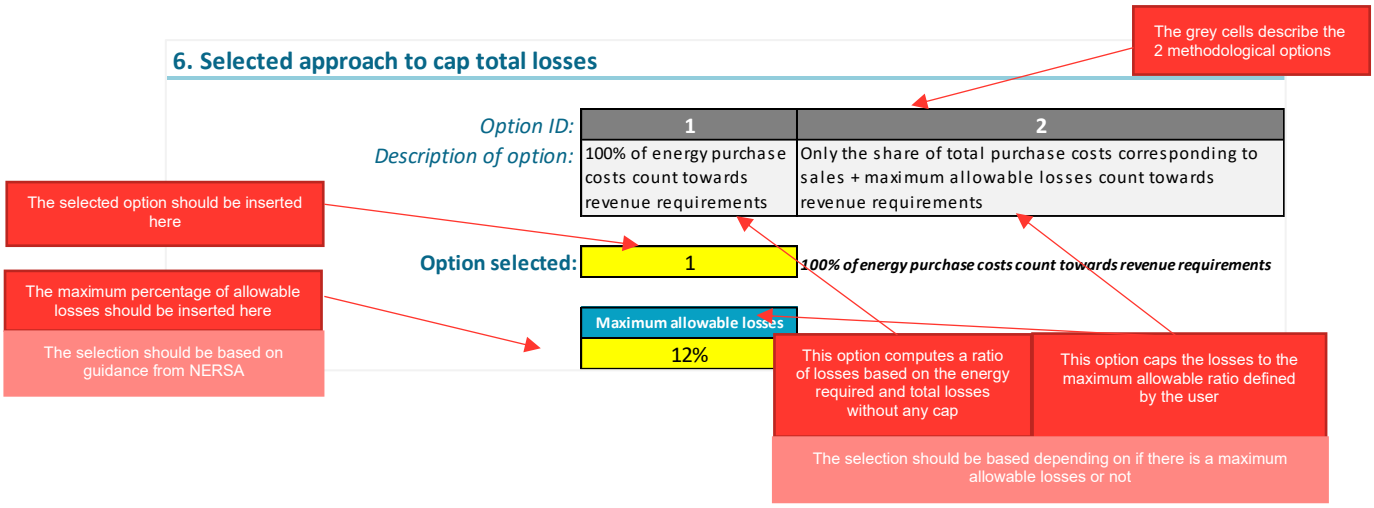
Note that if option 2 is selected, depreciation values related to retail assets should **not** be entered in the Financial Inputs (Year 0) or Financial Inputs (Years 1-4) sheets.

The **"*Selected approach to determine network asset O&M in any particular year*"** allows the user to define the methodology to assess the operations and maintenance costs.



Note that if option 2 is selected, repairs and maintenance values should **not** be entered in the Financial Inputs (Year 0) or Financial Inputs (Years 1-4) sheets.

The **"*Selected approach to cap total losses*"** allows the user to decide the level of allowable losses a utility can include in its revenue requirement.



Methodology note: Treatment of losses in the revenue requirement

The approach selected determines how the cost of total energy losses is treated in the revenue requirement. Total losses are calculated as the difference between total electricity purchases and total electricity sales. The model then determines whether the full cost of those losses, or only the cost associated with an allowable level of losses, is included in the revenue requirement:

a) **Full recovery of energy purchase costs** (100% of energy purchase costs count towards revenue requirements):
Under this option, the full cost of electricity purchases is included in the revenue requirement. This means that the cost associated with all calculated losses is recovered from customers, without applying a cap to the level of losses included in the revenue requirement. The total energy losses are calculated as the difference between purchased energy and billed sales.

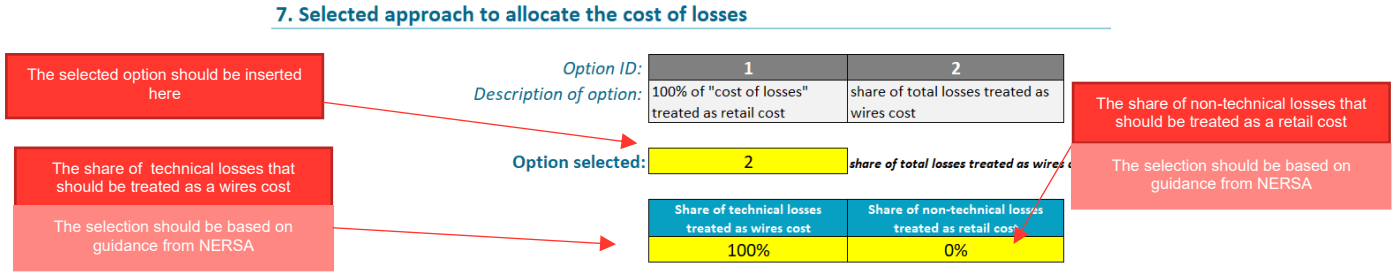
The cost of losses is then reflected through the portion of total electricity purchase costs that is attributable to the difference between purchases and sales.

b) **Recovery limited to sales plus allowable losses** (Only the share of total purchase costs corresponding to sales + maximum allowable losses count towards revenue requirements):

Under this option, the model limits the recoverable cost of losses to the maximum allowable loss ratio specified by the user. Only the electricity purchase costs associated with billed sales plus the allowable level of losses are included in the revenue requirement. Any losses above the allowable threshold are excluded from the revenue requirement and must therefore be absorbed by the municipality or addressed through loss-reduction measures.

The allowable loss ratio should reflect an efficient level of losses for the municipality, taking into account its network characteristics, operating conditions and applicable regulatory guidance. The COS Framework currently identifies a tolerable range of losses of 5% to 12%

The **"*Selected approach to allocate the cost of losses*"** allows the user to decide whether to allocate the cost of losses as a retail cost or as a share between the wires and retail business areas.



Methodology note: Allocation of losses

The user can select how the cost of losses is allocated in the model. The total cost of losses may either be treated entirely as a Retail cost, or allocated between the Wires and Retail business areas. The appropriate treatment depends on the methodology adopted for distinguishing between technical and non-technical losses and on the extent to which those losses are considered to arise from network-related activities or customer-related activities.

There is a basis for treating losses as a Retail cost where the cost is viewed as part of the energy purchase cost incurred in supplying electricity to end-use customers. Under this approach, the full cost of losses is recovered through the Retail revenue requirement and allocated to customer categories as part of the cost of electricity supplied.

There is also a basis for allocating a portion of losses to the Wires business area where those losses are technical in nature. Technical losses arise from the physical characteristics of the network, including conductor resistance, transformer losses and other inherent equipment losses associated with conveying electricity from the source of supply to the customer connection point. Where these losses are caused by the use of network assets, it may be appropriate to treat the associated cost as part of the Wires revenue requirement.

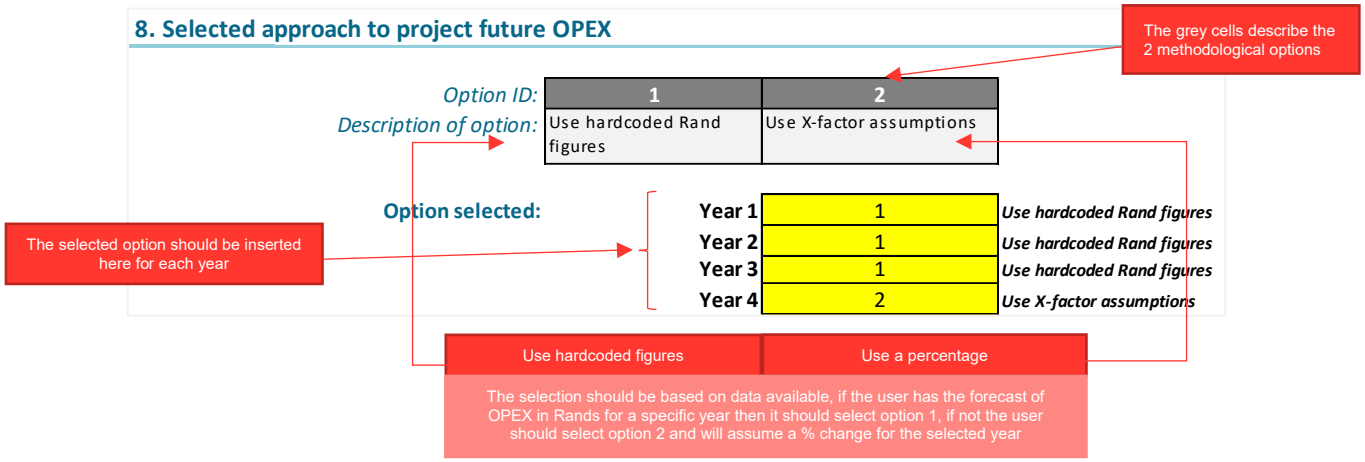
By contrast, non-technical losses are generally not caused by the physical operation of the network. They may arise from unauthorised connections, meter tampering, metering inaccuracies, billing errors, data handling errors, unbilled consumption or theft of electricity. These losses are typically more closely associated with customer management, metering, billing, revenue protection and commercial

processes, and may therefore be treated as a Retail cost unless a different allocation approach is justified.

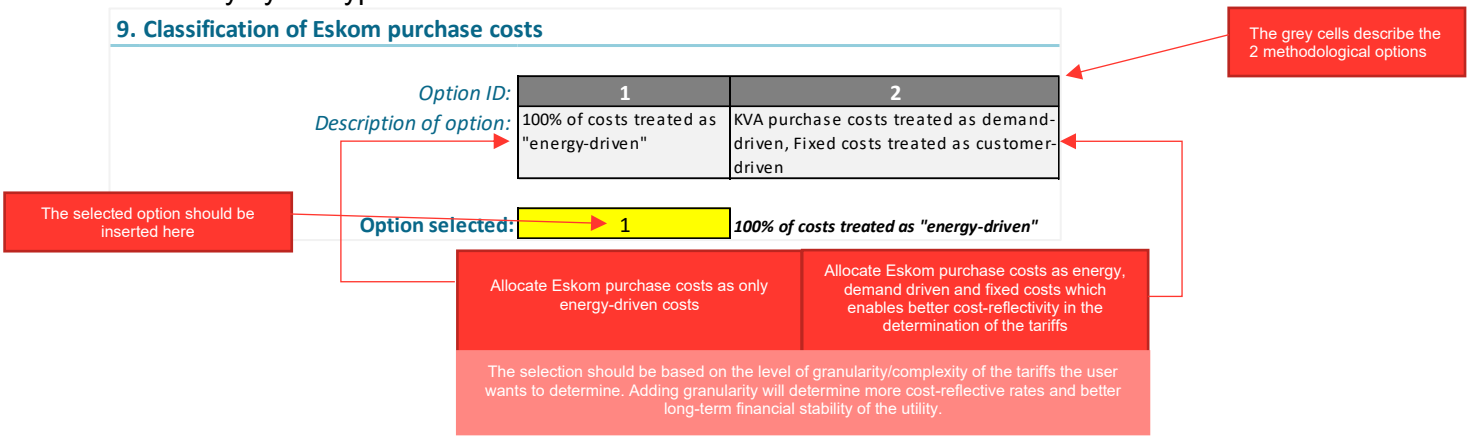
If the option to allocate losses between Wires and Retail is selected, the user must specify the share of technical losses to be treated as a Wires cost and the share of non-technical losses to be treated as a Retail cost. These allocation shares should be based on the municipality's available loss studies, network data, metering and billing information, and any other evidence supporting the attribution of losses to network or retail activities. Where reliable evidence is not available, the selected allocation should be treated as an assumption and clearly documented.

Further guidance from NERSA is required on the preferred regulatory treatment for allocating the cost of losses between Wires and Retail, particularly where technical and non-technical losses are separated for COS purposes. Until such guidance is provided, the model allows the user to test alternative allocation approaches, provided the selected assumptions are reasonable, transparent and consistently applied.

The **"*Selected approach to project future OPEX*"** allows the user to decide how to forecast future OPEX, either as a percentage increase/decrease or hardcoded figures for each year.



The **"*Classification of Eskom purchase costs*"** allows the user to define if Eskom's purchase costs should be only allocated as energy driven costs, or energy, demand driven and fixed costs. Energy driven costs vary with energy consumption, demand driven costs vary with the system peak demand, and fixed costs vary by the type of customer served.

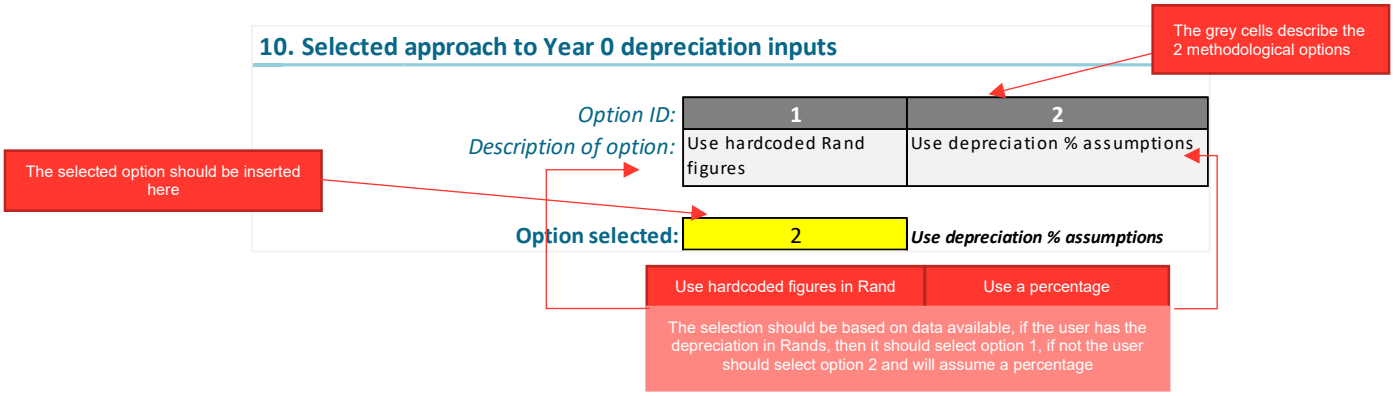


Methodology note: Classification of Eskom purchase costs

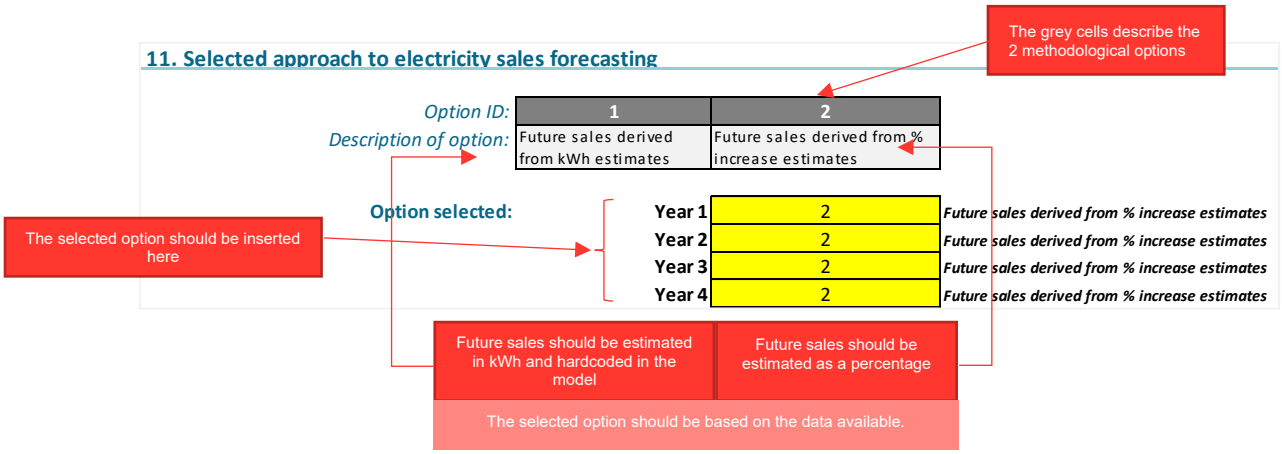
The user can define how Eskom purchase costs are classified in the model for cost allocation purposes. Eskom charges may either be treated entirely as energy-driven costs, or disaggregated and classified according to their underlying cost drivers, namely energy, demand and fixed or customer-related components. Where the relevant Eskom tariff data is available, disaggregating the purchase costs by cost driver provides a more accurate and cost-reflective treatment, because it recognises that not all Eskom charges vary only with energy consumption. Energy charges are driven by electricity consumed in kWh, demand charges are driven by the level of peak or notified demand in kVA or kW, and fixed or customer-related charges are driven by the existence of a connection, point of delivery or customer account rather than by the volume of energy consumed.

The selected classification affects how Eskom purchase costs are allocated to customer categories and ultimately how those costs are reflected in the COS results and tariff design. Treating all purchase costs as energy-driven is simpler and may be appropriate where detailed Eskom billing or tariff component data is not available. However, this approach may overstate the role of energy consumption in driving purchase costs and may understate the contribution of peak demand or fixed supply costs. Classifying Eskom charges according to their underlying cost drivers produces a stronger basis for developing cost-reflective rates, particularly where the municipality is exposed to demand-based and fixed Eskom charges through its bulk supply tariff.

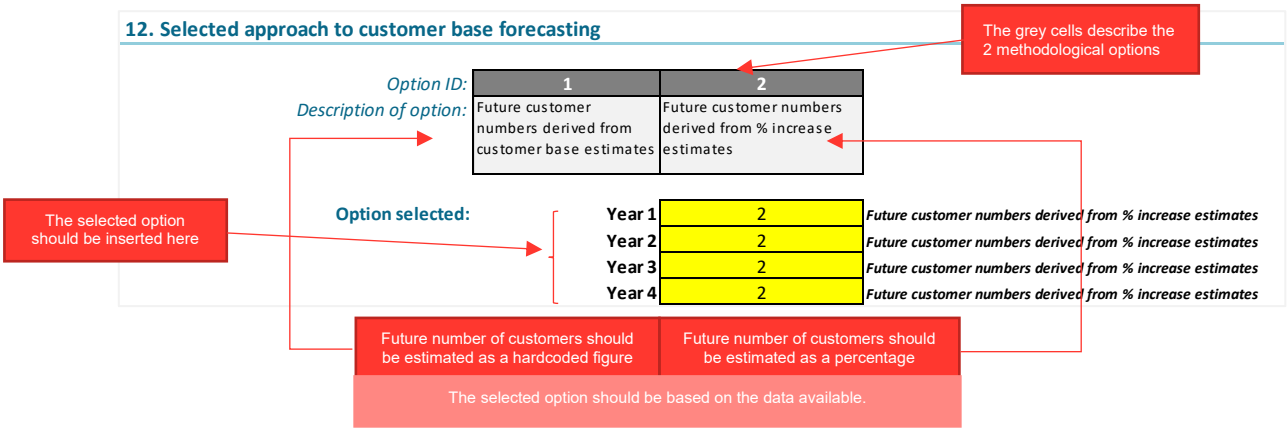
The **"*Selected approach to Year 0 depreciation inputs*"** is for the user to decide if the depreciation for Year 0 should be hardcoded in Rands or as a percentage.



The **"*Selected approach to electricity sales forecasting*"** allows the user to decide how to forecast future sales, either as a hardcoded figure in kWh or a percentage increase/decrease for each year.



The **"*Selected approach to customer base forecasting*"** allows the user to decide how to forecast the number of customers, either as a hardcoded figure or a percentage increase/decrease for each year.



The “**Multi-year authorised cost smoothing**” feature should be used for a multi-year tariff period where the intention is to achieve full cost-reflectivity while avoiding peaks and troughs in average rates.

The grey cells describe the 2 methodological options

The desired smoothing period should be inserted here.

This is the number of years starting from Year 2 that comprises the multi-year tariff period.

This is the average smoothing rate calculated by the model for the period.

This is calculated as the sales-weighted average over the smoothing period. This average rate, when applied over the smoothing period and considering the forecasted sales, would recover the total allowable revenue by the end of the period.

The selected option should be inserted here.

13. Multi-year authorised cost smoothing

Option ID:	1	2
Description:	No smoothing	Smoothing as defined below

Option selected: 2 *Smoothing as defined below*

Smoothing period (from Year 2) 3 *year(s)*

Average smoothing rate
2,32

	Inputs in column O to complete!	Allowable revenue (R) pre-smoothing	Total sales (kWh)	Average pre-smoothing cost (R/kWh)	Average post-smoothing cost (R/kWh)
1	2026	2 212 710 382	953 804 196	2,32	2,32
1	2027	2 271 120 939	978 982 473	2,32	2,32
1	2028	2 328 557 700	1 003 740 988	2,32	2,32
0	2029	2 513 517 591	1 028 149 476	2,44	2,44

This is a Boolean indicator of whether the respective year is included in the smoothing period (indicated by “1”) or not (“0”).

This is the allowable revenue pre-smoothing and the forecasted sales for Years 2 to 4 that is calculated by the model prior to the application of any smoothing.

This is the average pre-smoothing cost for each of the years.

For each year, this is calculated by dividing the allowable revenue pre-smoothing by the total sales.

This is the average post-smoothing cost for each of the years.

For each year, this is calculated by dividing the allowable revenue post-smoothing by the total sales.

HARD CODED VALUES ONLY!!!

Allowable revenues (R) post-smoothing	Recommended smoothing (R)	Selected smoothing (R)	Smoothing used (R)
2 212 710 382	(62 527 942)		-
2 271 120 939	(238 792)		-
2 328 557 700	62 766 734		-
2 513 517 591	-		-

This is the allowable revenues after the implementation of any smoothing.

This is calculated by multiplying the average smoothing rate by the total sales for each year.

This is the recommended smoothing adjustment calculated by the model.

This is the difference between the allowable revenue pre- and post-smoothing.

These are the smoothing adjustments selected by the user.

To implement the exact smoothing average rate, The values in column N should be copied into column O. Note that these cells should contain values, not formulas.

These are the smoothing adjustments that are implemented in the model.

If the smoothing option is selected, the values in column P are set as equal to those in column O.

HARD CODED VALUES ONLY!!!

Allowable revenues (R) post-smoothing	Recommended smoothing (R)	Selected smoothing (R)	Smoothing used (R)
2 212 710 382	-	(62 527 942,08)	(62 527 942,08)
2 271 120 939	-	(238 791,53)	(238 791,53)
2 328 557 700	-	62 766 733,62	62 766 733,62
2 513 517 591	-	-	-

Methodology note: Smoothing of rates and revenues

The multi-year authorised cost smoothing feature allows the user to choose whether revenues and average rates should be smoothed over a defined multi-year period. Under Option 1, no smoothing is applied. Under Option 2, the user can apply smoothing and test the effect of different smoothing periods. The smoothing period must begin in Year 2 and is identified by the “1”s in column C for each year included in the period. If Option 2 is selected, the model indicates that the smoothing adjustments must be populated in column O.

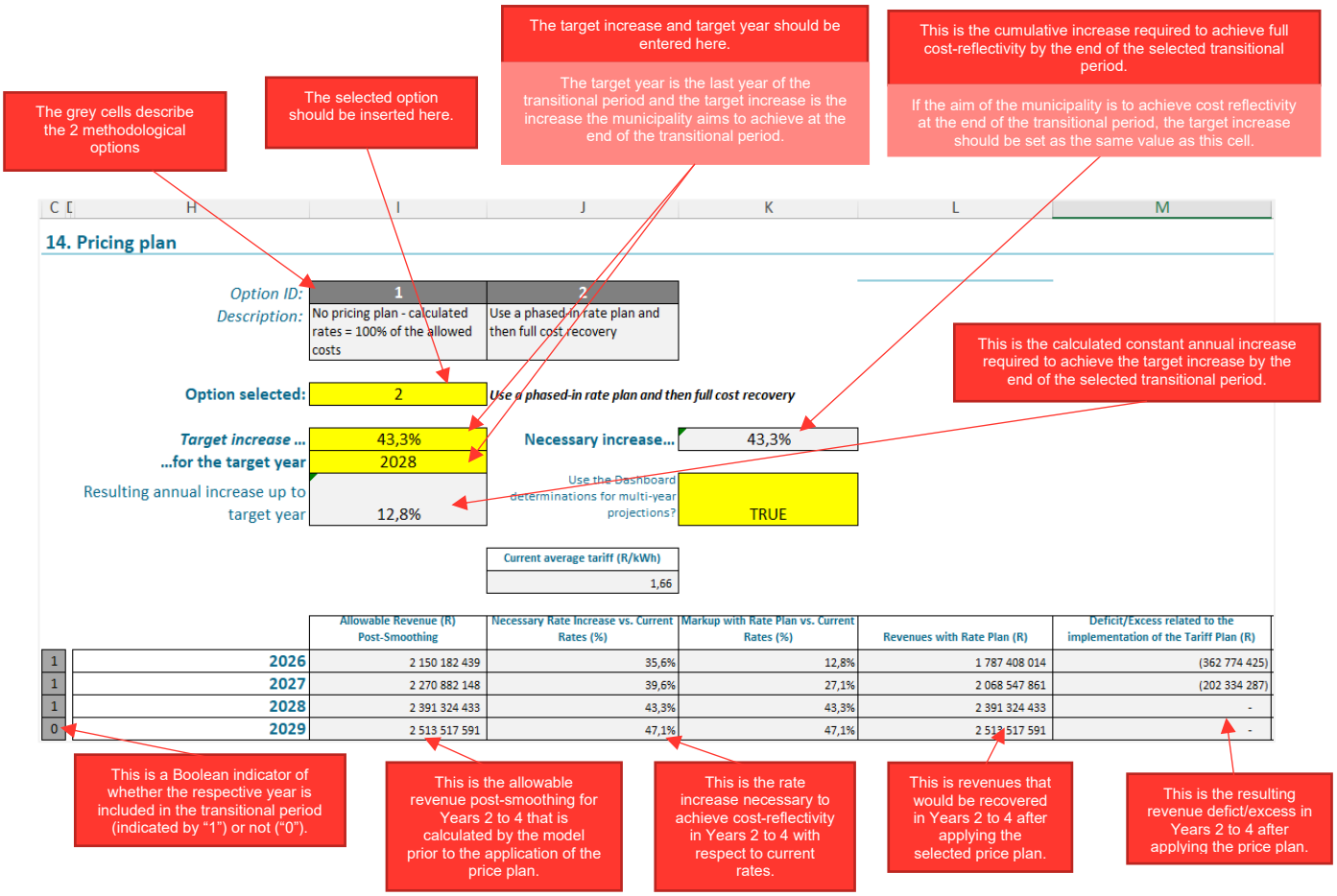
For each year in the selected smoothing period, the model first identifies the allowable revenue before smoothing, as shown in column I. It then calculates the constant average rate that, if applied in every year of the smoothing period, would recover the same total allowable revenue by the end of that period. This is effectively a sales-weighted average of the annual average rates over the smoothing period. The calculation changes the timing of revenue recovery, but not the total amount recovered, thereby allowing the municipality to maintain a more stable average rate across the period.

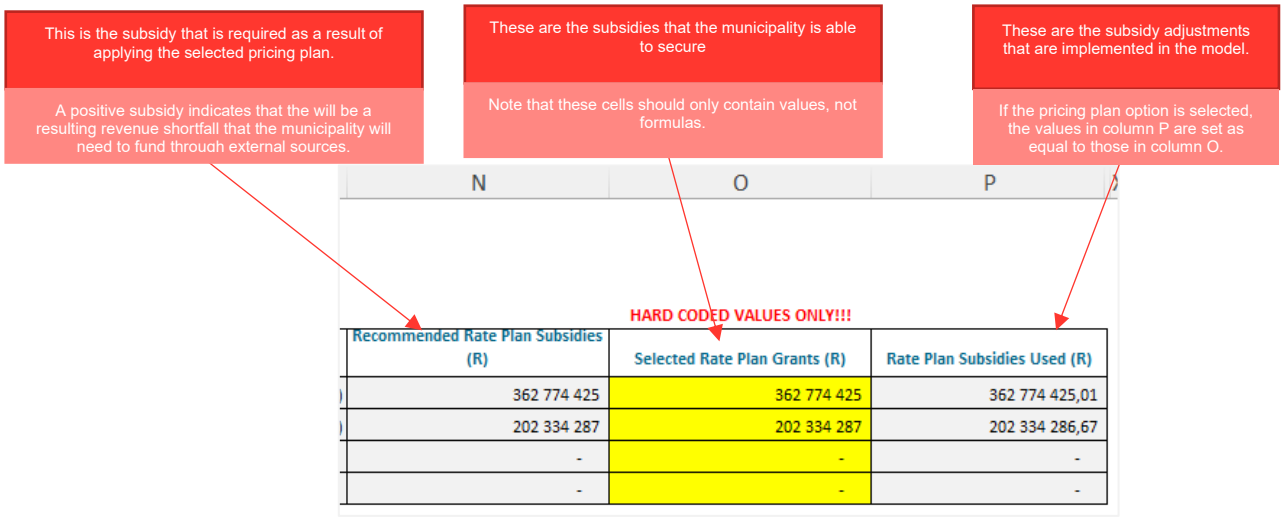
If the calculated smoothing rate is applied, the model determines the revenue that would be recovered in each year by multiplying the smoothing rate by forecast sales. This smoothed revenue is shown in column M and is compared with the pre-smoothing allowable revenue in column I. The resulting difference is shown in column N where a negative value indicates that the smoothed rate would recover more revenue than the pre-smoothing allowance in that year, while a positive value indicates that it would recover less.

To implement the model’s smoothing recommendation, the user must manually copy the values calculated in column N and paste them as values into column O. This step is not performed automatically by the model. The values entered in column O are treated as smoothing adjustments and are reflected in the Financial Inputs (Years 1–4) sheet under ‘Other Revenues’.

Because the smoothing rate represents the average rate required over the full smoothing period, the tariff schedule established in Year 2 effectively sets the average tariff level for that period. The rate should therefore remain sufficient to recover the projected total revenues without annual changes, provided that the model inputs and forecasts do not change materially. If there are material changes to sales, costs or other forecast assumptions, the smoothing calculation and resulting tariff schedule should be reviewed.

The “**Pricing plan**” feature replaces the Tariff Transition panel that was previously included on the Rate Design Dashboard. It allows the user to determine whether the municipality will move immediately to cost-reflective rates or follow a phased transition over several years.





Methodology note: Pricing plan

Under Option 1, no transition plan is applied. Under Option 2, the user can introduce a transitional pricing plan. Column I shows the revenue to be recovered in each year after taking account of any multi-year smoothing adjustment applied in the preceding step. Column J compares the revenue that would be recovered under business-as-usual rates with the revenue required for cost reflectivity in that year and therefore indicates the cumulative rate increase required to move from the business-as-usual position to full cost reflectivity.

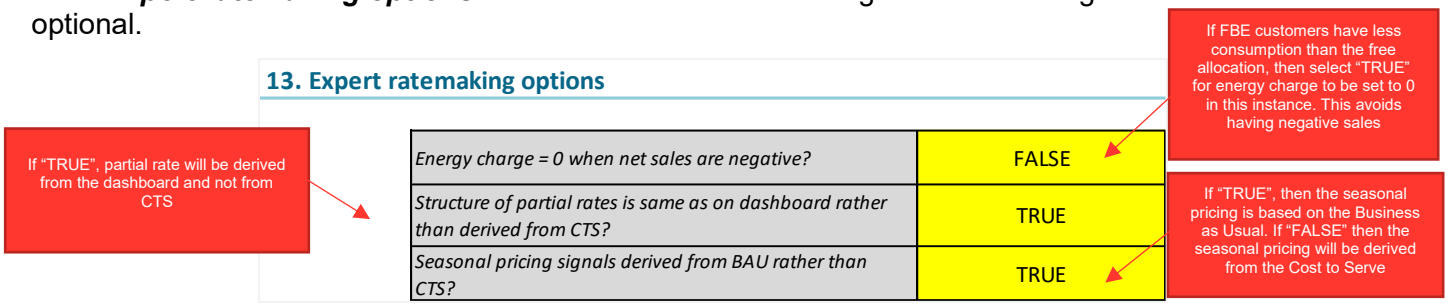
The user must enter the final year of the transition period in cell I381. This is the year by which the municipality aims to achieve the targeted sustainable tariff outcome. The user must then specify the cumulative rate increase targeted by that year. The cumulative increase required to achieve full cost reflectivity by the end of the selected transition period is shown in cell K180. If the intention is to reach full cost reflectivity, the user should enter the same percentage in cell I180 as the value calculated in cell K180.

Based on the selected transition period and targeted cumulative increase, the model calculates the constant annual rate increase required to achieve the target by the end of the selected year. This represents the year-on-year increase that must be applied consistently over the transition period to reach the specified cumulative increase.

The model also calculates the annual revenue deficit/excess that would arise from applying the determined year-on-year increase instead of moving immediately to cost-reflective rates. The deficit represents the resulting under-recovery of allowable revenue in each year of the transition period and any excess represents over-recovery. To implement the pricing plan, the municipality will need to fund any projected shortfall from external sources. In the model, the user must manually copy the values calculated in column O and paste them into column P. This automatically populates row 23 of the FBE Inputs (Years 1–4) sheet. It also updates cell I24 in the Rate Design Dashboard (Year 2) sheet, which shows the average rate increase required under the transition plan and provides the target to be achieved through the tariff design process on that sheet.

This feature is intended for circumstances where the municipality cannot reasonably achieve full cost reflectivity in a single year and therefore needs to phase the required tariff increase over several years.

The **"*Expert ratemaking options*"** is for the user to make changes when defining rates. This section is optional.



Methodology note: Expert ratemaking options

The expert ratemaking options provide additional controls that affect how the tariff design module interprets the COS results and translates them into proposed end-user rates. These options are not mandatory inputs for completing the COS calculation, but they allow the user to refine specific aspects of the rate design where additional judgement or policy direction is required.

- The first option addresses the case where Free Basic Electricity (FBE) customers consume less than the free allocation. If this option is set to "TRUE", the model sets the applicable energy charge to zero, preventing the calculation of negative billable sales or negative revenue. This ensures that the tariff calculation remains internally consistent where the free allocation exceeds actual consumption.
- The second option determines how the structure of partial rates is derived. The shares of revenue to be recovered through energy, demand and fixed charges may either be based on the user's selections on the rate design dashboard or derived from the CTS results. Using the dashboard selections allows the municipality to retain greater control over the proposed tariff structure, while using the CTS results provides a more cost-reflective allocation of revenue recovery across charge types.
- The final option determines how seasonal pricing signals are derived. Seasonal energy rate differentials may either be based on the municipality's existing seasonal tariff structure, where one is already applied, or derived from the CTS results. Retaining the existing seasonal signal may be appropriate where the municipality wishes to avoid unnecessary tariff instability or preserve established billing arrangements. Deriving the seasonal signal from the CTS results may be more appropriate where the objective is to align seasonal rates more closely with the underlying seasonal cost to serve.

The ***"Failsafe parameters"*** section allows the user to define upper-bound reasonableness checks that limit the risk of implausible or unintended model outputs. These parameters are optional and should be used to test or constrain results where underlying input data is incomplete, uncertain or potentially inconsistent.

Failsafe parameters	
Maximum Non Eskom contribution to meeting PD	50%
Maximum technical losses	10%
Maximum system load factor	100%

Methodology note: Failsafe parameters

Failsafe parameters are control inputs used to prevent the model from producing results that are outside a reasonable range where the underlying data may be incomplete, inconsistent or uncertain. They do not replace the need for accurate input data, but provide an additional reasonableness check to reduce the risk that outlier inputs or incomplete data materially distort the COS results.

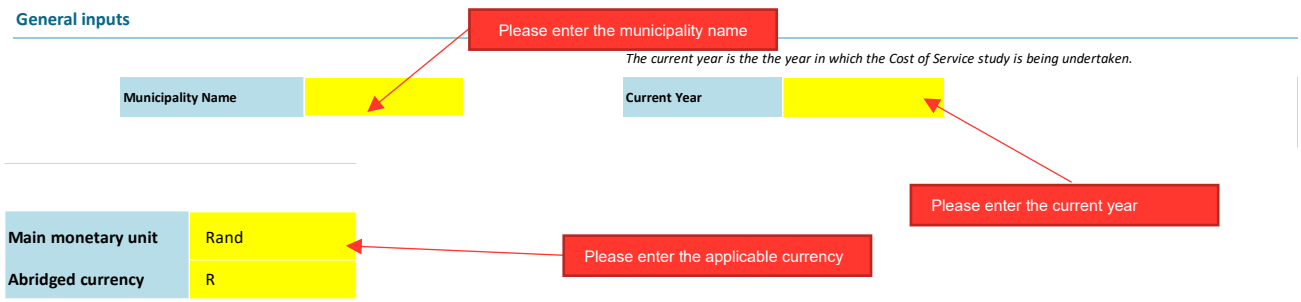
- The **maximum non-Eskom contribution to meeting peak demand** defines the maximum proportion of coincident system peak demand that can be assumed to be supplied by non-Eskom sources. This prevents the model from overstating the extent to which non-Eskom purchases reduce the municipality's reliance on Eskom capacity at system peak. It therefore helps to avoid understating the Eskom-related demand requirement and the associated demand-driven purchase costs.
- The **maximum technical losses** parameter defines the maximum share of energy purchases that may be treated as technical losses. This acts as a cap on the technical loss estimate where the technical loss factors entered in the model may be unreliable or may produce an implausibly high technical loss result. By limiting the technical loss component, the model reduces the risk that non-technical losses are understated as a residual difference between total losses and calculated technical losses.
- The **maximum system load factor** parameter is used as a reasonableness check on the relationship between annual energy requirements and system peak demand. Because load factor reflects the extent to which energy consumption is spread across the year, setting a maximum system load factor prevents the model from deriving an unrealistic peak demand. This parameter is used in the demand scaling adjustment calculation inputs that can be found in the Technical Inputs (Years 1-4) sheet. This helps ensure that the calculated system peak demand remains within a plausible range for the municipality's load profile.

At this stage of the COS analysis, the user has decided on all methodology options to determine the tariffs. In the next sections, the user must provide additional assumptions and historical/forecasted values to compute the tariffs.

2.2.3 Capturing data into the model's “Index Tables” worksheet

In this step, the user must populate the index tables, which the model will refer to throughout the COS analysis. This sheet must be completed before completing any following sheets as it labels all the inputs and provides additional methodology options. The following figures define each table in the “Index Tables” worksheet and the required actions by the user.

The **“*General Inputs*”** includes the municipality name, current year and applicable currency. The “*Municipality name*” needs to be filled in to identify the utility. The *“Current Year”* requires the user to input the current year (Year 1) which is the year in which the COS study is being undertaken.



The **"*Index of voltage levels*”** defines the different voltage levels within the municipality’s network. These voltage levels are used to compute the costs related to the associated assets and to determine losses for each voltage level.

Index of voltage levels

Sets the level of granularity of the cost allocation - can cover more than one voltage level in the utility's SLD. Should be ordered from highest to lowest voltage level.

	Label	Min voltage level (kV)	Max voltage level (kV)	Split urban/rural ?
Voltage level #1	33 - 88 - 132 kV	33	132	FALSE
Voltage level #2	11 kV	11	11	FALSE
Voltage level #3	400 V	0.4	0.4	FALSE

The user should define the different voltage levels of the municipality with the minimum and maximum voltage levels. This will be included in the calculation of the total assets (CAPEX) along with the losses for each voltage level

The voltage level should be found in the single line diagram of the network.

If there is a split between urban and rural for a specific voltage level, the user should select "TRUE"

The split should be found in the network diagram of the utility.

The "***Index of customer categories***" is essential to provide key information on customers and allows the model to determine different tariffs for each customer category.

Index of customer categories

Sets the level of granularity of the cost allocation - can cover more than one voltage level in the utility's SLD

	Label	RND asset group including intake point	Monthly data available?	TOU data available and TOU tariffs in place?	Use manual % inputs for TOU allocation?	Services provided include BOTH wheeling & retail?	Wheeling boolean	Category Group	New category in Year > 0?	Category most similar to new one
Customer category #1	Free Basic Electricity (FBE)	400 V / Mixed	TRUE	FALSE	FALSE	TRUE	1	Domestic customers	FALSE	Free Basic Electricity (FBE)
Customer category #2	Domestic (pre-paid)	400 V / Mixed	TRUE	FALSE	FALSE	TRUE	1	Domestic customers	FALSE	Domestic (pre-paid)
Customer category #3	Business (conventional)	400 V / Mixed	TRUE	FALSE	FALSE	TRUE	1	Commercial customers	FALSE	Business (conventional)

The user must include all customer categories' names and allocate the relevant voltage level intake points to each category. It then must specify whether monthly energy purchase data is available for each customer category

The customer categories' names should be found in the customer billing data along with monthly sales (if available). The network diagram will provide information on the type of asset group for each customer category.

The user is to define whether Time Of Use (TOU) data is available (distinction between OffPeak, Standard and Peak periods) for each customer category

This information should be included in the customer billing data.

If TOU data is not available but the user wants to include it in the determination of tariffs, it can by selecting "TRUE". This will add an option later on to add a percentage for each TOU period for each customer category

This percentage should be determined based on the time period of peak demand.

The user is to define for each customer category if they benefit from both wheeling and retail services or not

This information should be included in the customer billing data.

The user must allocate a category group to each customer category for analysis purposes.

This information should be based on understanding of the customer categories.

If the user wants to add a new customer category, it needs to allocate it to the most similar current customer category

This information should be based on understanding of the customer categories.

Data entry note: Index of customer categories

- The user should only select option "TOU data available and TOU tariffs in place" as TRUE if the user enters monthly, TOU data in Commercial Inputs (Year 0) sheet **OR** manual TOU and seasonal ratios are used. Otherwise this option should be set as FALSE.
- For customers with no kWhs sold:
    - If this is a new customer category in Year > 0, then the user would need to add this new customer class in the Index Tables sheet and indicate it is a new customer category in column Q. The user would also need to indicate which customer category the new category is most similar to in column R.
    - Under Methodology Inputs, the user would need to select the approach to customer base forecasting to option 1 "Future customer numbers derived from customer base estimates" for the relevant year(s) in which there will be customers connected to the network with this tariff.
    - The user would then need to enter the customer base estimations for all customer categories for the selected year(s)
    - Technical Inputs (Years 1-4): user to select the units for load profile inputs as "Average kVA/customer" and enter the appropriate value. Although this will not result in a R/kVA/month charge as the technical calibration is performed for year 0.
    - The results can be seen in the COS Results (Year 2) sheet H61:AO92. (note that this will only be a R/customer/month rate).

The **"*Index of functions*"** is to identify the OPEX category costs and allocates them to their business areas and cost classes (energy-driven, demand-driven and fixed costs). Energy-driven costs vary with the consumption of energy, Demand-driven costs vary with the system peak demand, and Fixed costs vary by the type of customer served.

Business areas:	Wires	Retail

	Label	Function included in Wires OPEX list	Function included in Retail OPEX list	Split by class: Energy	Demand	Customer	Function included in margin baseline?	Function related to purchasing costs?	Label - Wires only	Label - Retail only
Function #1	*Eskom Energy Purchase - excl. losses*	FALSE	FALSE				FALSE	TRUE		
Function #2	*Eskom Energy Purchase - cost of losses*	FALSE	FALSE				FALSE	TRUE		
Function #3	*Other Energy Purchase*	FALSE	FALSE	100%	0%	0%	FALSE	TRUE		
Function #4	*CAPEX and return*	TRUE	FALSE	0%	100%	0%	FALSE	FALSE	CAPEX and return	
Function #5	*Depreciation*	TRUE	TRUE	0%	100%	0%	TRUE	FALSE	Depreciation	Depreciation
Function #6	*Network repairs & maintenance*	TRUE	FALSE	0%	100%	0%	TRUE	FALSE	Network repairs & maintenance	
Function #7	Marketing	FALSE	TRUE	0%	0%	100%	TRUE	FALSE		Marketing
Function #8	Metering	FALSE	TRUE	0%	0%	100%	TRUE	FALSE		Metering
Function #9	Other OPEX	TRUE	TRUE	0%	0%	100%	TRUE	FALSE	Other OPEX	Other OPEX

The user is to include any OPEX category that exists in their financial statements. Further, each item should be split by business area i.e wires or retail

This information should be included in the financial statements of the utility.

The OPEX categories are to be classified as energy, demand, fixed or a combination of these on a % basis

The percentage should be assumed based on the types of OPEX item included in the function.

The user must choose whether each OPEX category should be included in the determination of the allowable margin on OPEX and if it relates to purchasing costs

If method 3 (margin on OPEX) is selected when defining the revenue requirement approach in the "Methodology Input" sheet, the user needs to define if each OPEX category should be included in the margin calculation. If the user selects "TRUE" that means that all costs in this OPEX category will be included in the OPEX used to compute the margin.

Function designating asset depreciation:	Depreciation
Function designating network asset O&M:	Network repairs & maintenance
Function designating CAPEX:	CAPEX and return
Function to allocate "purchase margin" when applicable	Network repairs & maintenance

These are the pre-defined functions related to depreciation, network asset O&M, CAPEX and purchase margin (when applicable). This is to inform the model on the category cost that should be allocated for these 4 key functions. The purchase margin is the additional purchases that should be included in the calculation of the allowable margin on OPEX net of purchases

The **"*Index of Eskom intake points*"** allows the user to label each Eskom Point Of Delivery (POD) when computing Eskom purchase volumes.

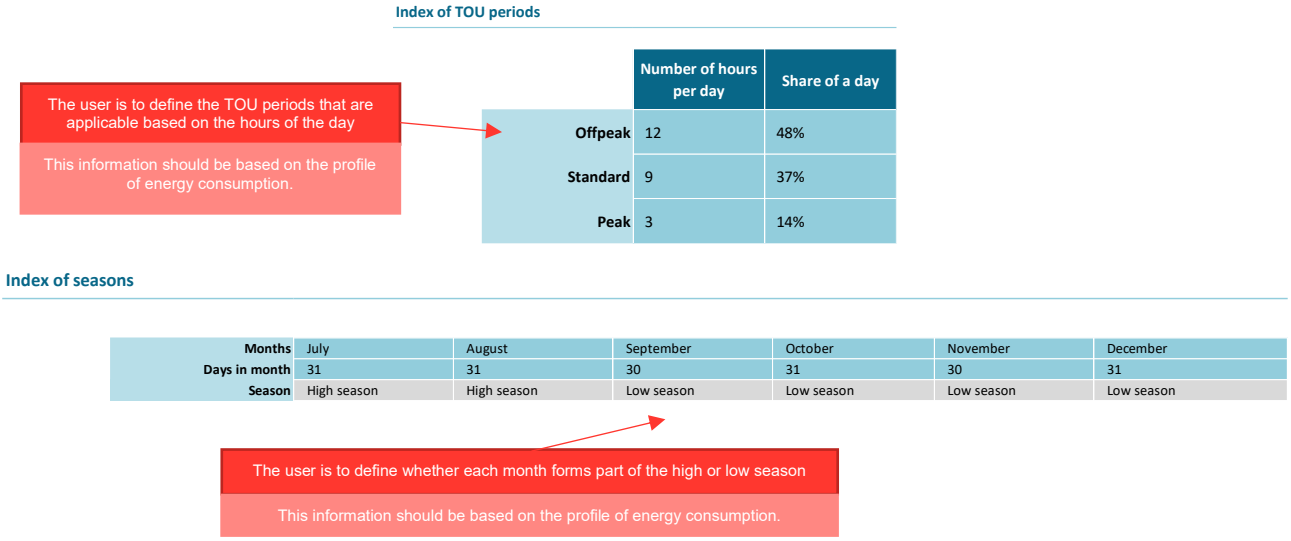
Index of Eskom intake points

	Name	Monthly data available?
POD #1		FALSE
POD #2		FALSE
POD #3		FALSE
POD #4		FALSE
POD #5		FALSE

The user must add the required number and names of Points Of Delivery (PODs) based on the system. The user must also indicate whether monthly data is available for each POD.

This information should be in the billing data from Eskom.

The **"*Index of Time Of Use (TOU) periods*"** and seasons is for the user to define the number of hours per day for each TOU period and which months are considered high and low seasons. This is relevant to compute tariffs based on the TOU and/or the season.



The **"*Index of Eskom tariffs and charges*"** relates to the type of charges billed by Eskom along with its unit and if TOU is available. The unit types are then allocated to the 3 categories of charges: Energy, Demand and Fixed.



The **"*Index of non-Eskom power purchases categories*"** is for the user to define the label of the other power purchases categories. Note that "*DG Exports*" refers to purchases from distributed generators.

Index of non-eskom power purchases categories

	Label
Power purchase category #1	*DG Exports*
Power purchase category #2	Independent Power Producers Conventional
Power purchase category #3	Independent Power Producers Renewable Energy
Power purchase category #4	Self Generation
Power purchase category #5	Other

The **"*Index of utility tariffs and charges*"** is for the user to define the label and unit of all customer charge types billed to the end customer.

Index of utility tariffs and charges

	Charge	Unit
Customer Charge Type #1	Active Energy Rate	c/kWh
Customer Charge Type #2	Maximum Demand Charge	R/KVA/month (MD)
Customer Charge Type #3	Basic charge	R/POD/month
Customer Charge Type #4		
Customer Charge Type #5		

The user is to define the charge type with the unit billed by the utility.

All this information should be included in invoices to the end-customer.

At this stage of the COS analysis, the user has decided on all methodology options and defined key labels of all inputs to determine the tariffs. In the following sections, the user must provide historical/forecasted values to compute the tariffs.

2.2.4 Capturing the Timeframe for the COS Study

This sheet allows the user to review the timeframe of the COS study. The model incorporates a multi-year perspective regarding data and calculations. This sheet allows the user to view the timeframe of the study and to change the Year 1 reference. If this input is changed, the other reference years will automatically update.

Timeframe for Cost to Serve Study

The Applicable Year indicates the financial year ending.

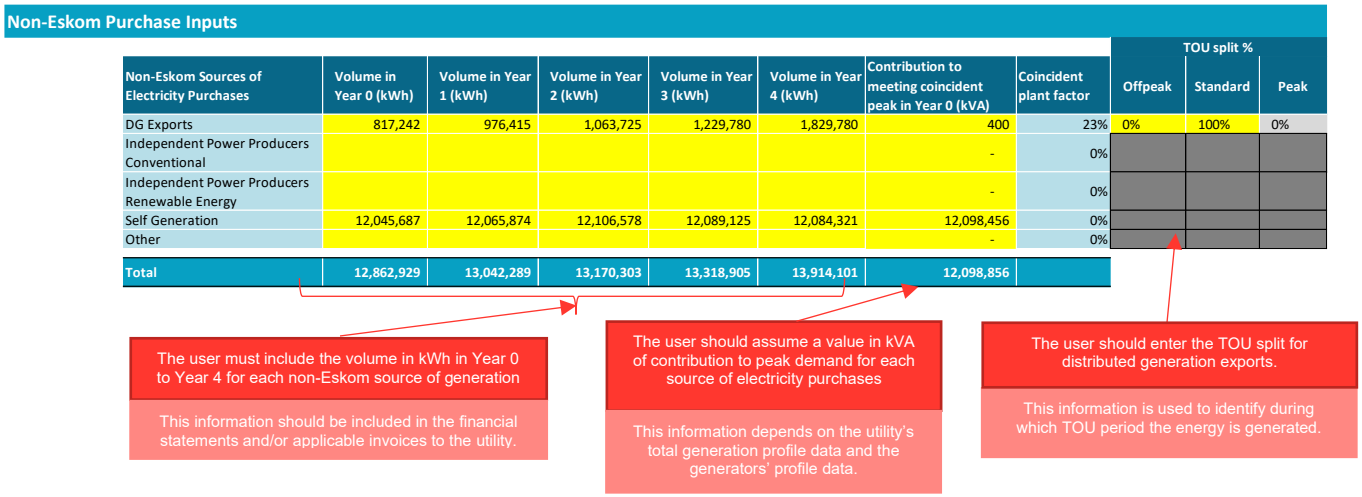
Reference Year	Applicable Year	
Year 0	2025	*When data sets are last complete.*
Year 1	2026	*When the CTS study is carried out.*
Year 2	2027	*When new rates are implemented.*
Year 3	2028	
Year 4	2029	

The user can change the Year 1 reference year in Methodology Inputs.

Year 1 is the year in which the COS study is being undertaken.

2.2.5 Capturing Non-Eskom Power Purchase Inputs

This step requires the user to capture any other sources of electricity that may exist outside of the electricity purchased from Eskom. As mentioned in section 1.3.3 Year 0 refers to the historical data (i.e., when the last complete set of data is available). The following figure highlights the inputs required in this step.



Methodology note: Non-Eskom power purchase inputs

The non-Eskom power purchase inputs capture electricity purchased or received from sources other than Eskom, including independent power producers, embedded generators, distributed generation exports or other contracted supply arrangements. These inputs are used to ensure that the model reflects the municipality's full electricity supply mix, rather than treating Eskom as the only source of purchased energy.

- For each applicable year, the energy volumes from non-Eskom sources are included in the energy balance. To determine the energy balance for Year 2 in which rates are designed, the model considers the forecasted sales and losses to determine the total energy requirements. The non-Eskom purchase volumes are then used to determine the residual energy requirement to be met through Eskom purchases. Where non-Eskom supply increases, the model reduces the volume of energy that must be purchased from Eskom, subject to the assumptions entered by the user and the timing and availability of the non-Eskom supply.
- Where applicable, the user must also specify the extent to which non-Eskom supply contributes to meeting coincident system peak demand. This input is important because not all non-Eskom energy purchases reduce the municipality's Eskom demand requirement at the time of system peak. The model uses this contribution to calculate the remaining peak demand that must be supplied by Eskom, which affects the demand-related component of bulk supply costs.
- The inputs also affect the calculation and allocation of bulk supply costs. Non-Eskom purchases may change the mix of energy, demand and fixed costs included in the revenue requirement, depending on the applicable purchase agreements, tariffs and the extent to which these purchases offset Eskom energy and demand charges. The user should therefore ensure that the non-Eskom volumes, prices, timing and peak contribution assumptions are consistent with the relevant contracts, invoices, generation profiles or settlement data.

2.2.6 Capturing Asset Register Inputs (Year 0)

This step requires the user to provide the total value of the asset register by voltage level in Year 0, along with the depreciation rate of these assets. Where the municipality's existing asset register is not already available in the format required by the model, the Asset Register Template may be used to capture and

structure the relevant asset information for input into the COS model. As mentioned in section 1.3.3, Year 0 refers to the historical data (i.e., when the last complete set of data is available). The following figures highlight the inputs that are required.

Summary of network asset register analysis - closing balance end of Year 0

					0	1					
Asset Group Label	Asset Value (Rand)	Total length of lines (km)	Wires Share (%)	Retail Share (%)	Annual depreciation - manual input	Depreciation rate - manual input	Annual depreciation - calculated	Annual depreciation rate - calculated	Accumulated depreciation to date	Net depreciated value	Annual O&M as % of replacement value
33 - 88 - 132 kV / Mixed	R 6,400,000,000	0.0	100%	0%		2.0%	R 128,000,000	2%	R 541,175,169	R 5,858,824,831	0%
11 kV / Mixed	R 3,320,301,796	0.0	100%	0%		2.0%	R 66,406,036	2%	R 2,508,700,148	R 811,601,648	0%
400 V / Mixed	R 6,195,292,318	0.0	100%	0%		2.0%	R 123,905,846	2%	R 4,865,130,208	R 1,330,162,110	0%
	R 15,915,594,114						R 318,311,882		R 7,915,005,525	R 8,000,588,589	

The user must add the total asset value in Rands of the various network assets for Year 0 as well as their total lengths in km

This information should be included in the network diagram and financial asset register.

The user must add the annual depreciation either in Rands or as a percentage depending on the chosen methodology

This information should be included in the financial statements and financial asset register.

The user must add the accumulated depreciation to date in Rands for each asset group

This information should be included in the financial statements and financial asset register.

The user must add the assumed annual operation and maintenance as a percentage of replacement value

This information should be assumed based on financial statements.

Summary of other assets register analysis - closing balance end of Year 0

Asset Group Name	Asset Value (Rand)	Wires Share (%)	Retail Share (%)	Annual depreciation - manual input	Depreciation rate - manual input	Annual depreciation	Annual depreciation rate - calculated	Accumulated depreciation to date	Net depreciated value
Retail Asset	R 57,275,657	0%	100%		2.0%	R 1,145,513	2%	R 2,149,599	R 55,126,058
		0%	100%			R -	0%		R -

The user must add any "other" major assets (excluding the network assets inputted in the table above) with its asset value in Rands

This information should be included in financial statements and financial asset register.

Based on the type of asset, the user should assume the allocation between the wires and retail share

This assumption should be based on how the asset is used. It could be derived based on the wires/retail sales or purchases

The user must add the annual depreciation in Rands or as a percentage depending on the chosen methodology

This information should be included in financial statements and financial asset register

The user must add the accumulated depreciation to date in Rand for each asset group

This information should be included in financial statements and financial asset register

Methodology note: Regulatory asset base determination

The asset register inputs are used by the model to determine the value of assets included in the revenue requirement calculation where the user selects a Rate of Return or asset-based capital recovery approach. These values form the basis for calculating the allowable return, depreciation or annualised capital-related cost associated with the Wires and Retail business areas. The methodology selected for valuing the asset base is therefore material to the COS results and should be applied consistently across asset categories and years.

To support municipalities in providing the required information, an **Asset Register Template** has been specifically developed for use with the COS model. The template is intended to assist municipalities in capturing asset register information in a structured and consistent format, including the classification of assets by asset type, business area, voltage level, asset value and depreciation-related information. Where a municipality does not already maintain its asset register in a format that aligns with the model input requirements, the Asset Register Template should be used to organise and translate the available asset information into the inputs required by the model.

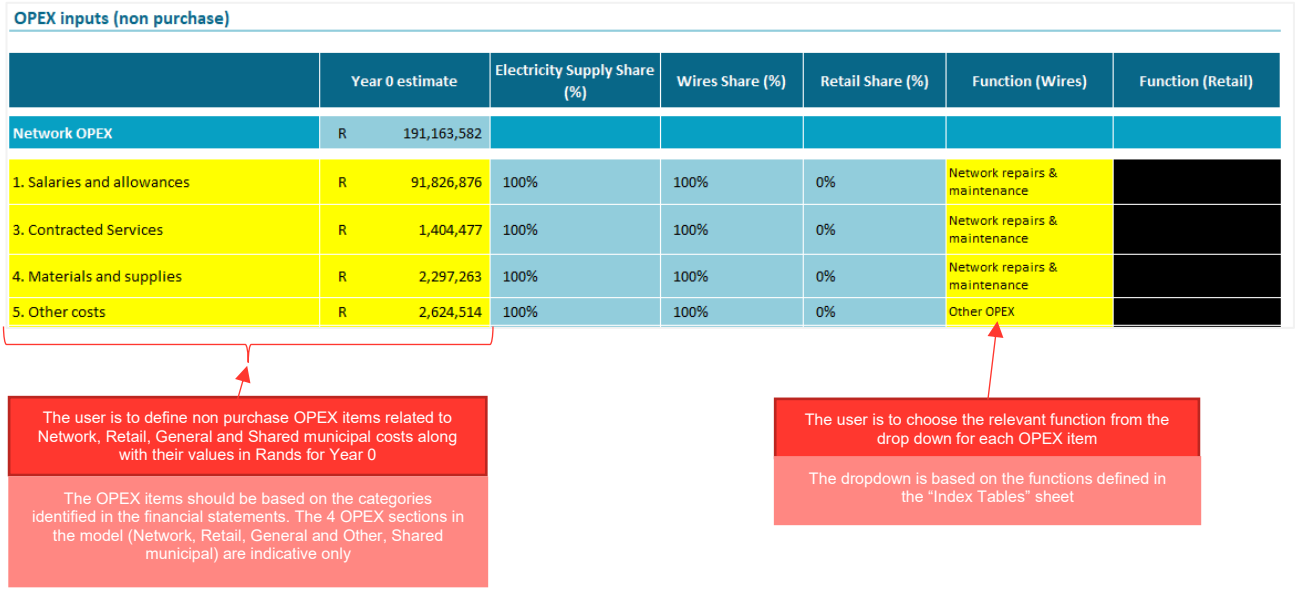
- Where a Rate of Return approach is used, the asset values entered in this section are used to approximate the regulated asset base to which the selected rate of return is applied. Further explanation of the Rate of Return methodology is provided in Section 2.2.2. The user should therefore ensure that the asset values entered are complete, reconciled to the underlying asset register or financial records, and aligned with the valuation basis as specified by NERSA.
- The valuation basis is important because different approaches can produce materially different asset values and therefore materially different revenue requirements.

- A historic cost approach is based on the original cost of the assets, adjusted where applicable for accumulated depreciation. This approach may be easier to support from accounting records, but may understate the economic value of older assets where historic costs are significantly below current replacement costs. If asset values are understated, the calculated return or capital recovery allowance may also be understated, which could result in insufficient funds being recovered to support future asset replacement and network sustainability.
- A current replacement cost approach estimates the cost of replacing the assets with assets of equivalent service capability at current prices. This approach may provide a stronger indication of the capital required to sustain the network over time, but it is more data-intensive and may result in higher asset values and therefore a higher allowable return or capital recovery allowance.

- The selected valuation basis should therefore be clearly documented and supported by available evidence. Further guidance from NERSA is required on the preferred valuation approach for municipal COS studies, including whether asset values should be based on historic cost, depreciated replacement cost, current replacement cost or another regulatory asset base methodology.

2.2.7 Capturing Financial Inputs (Year 0)

This step involves the user capturing the financial inputs relating to OPEX, non-electricity revenues as well as non-Eskom purchase inputs. As mentioned in section 1.3.3, Year 0 refers to the historical data (i.e., when the last complete set of data is available). The following figures highlight the required actions within this sheet.



Non-electricity supply revenues *(will be netted out of OPEX)*

	Year 0 estimate	Electricity Supply Share (%)	Wires Share (%)	Retail Share (%)	Function (Wires)	Function (Retail)
Other revenues						
Recon disconnect/Reconn Fees	R 1,927,256	100%	0%	100%		Other OPEX
Service connections	R 1,427,703	100%	100%	0%	CAPEX and return	
Meter Readings Fees	R 6,366	100%	0%	100%		Other OPEX
Sundry Income	R 590,584	100%	50%	50%	Other OPEX	Other OPEX
Merchandising Jobbing & Contracts	R 3,176,172	100%	50%	50%	Other OPEX	Other OPEX

The user is to define other revenue items along with the amount in Year 0 in Rands

This should be included in financial statements.

The user should allocate the contribution of this revenue to the electricity function

Some revenues might not be only from the electricity function. In this case the user can allocate a ratio to account for the electricity function contribution.

The user should allocate the revenue to each business area

This assumption should be based on the source of the revenue. A ratio could be determined based on the revenues of each business area.

The user is to choose the relevant function from the dropdown for each revenue item

The dropdown is based on the functions defined in the "Index Tables" sheet.

Non-Eskom Purchase Inputs

Sources of Electricity Purchases	Type of purchase cost input	Purchase costs in Year 0	Average rate in Year 0 in cR/kWh	Annual escalation	Average rate in Year 2 (cR/kWh)
DG Exports	Average rate in Year 0 in cR/kWh				-
Independent Power Producers Conventional	Purchase costs in Year 0				-
Independent Power Producers Renewable Energy	Purchase costs in Year 0				-
Self Generation	Purchase costs in Year 0				-
Other	Purchase costs in Year 0				-
Total		R -			R -

The user must define Non-Eskom purchase cost in Rands or the average rate in cR/kWh

This should be included in financial statements

The user must define an annual escalation factor to these purchases as a percentage

This should be included in financial statements

2.2.8 Capturing Eskom Power Purchase Volumes (Year 0)

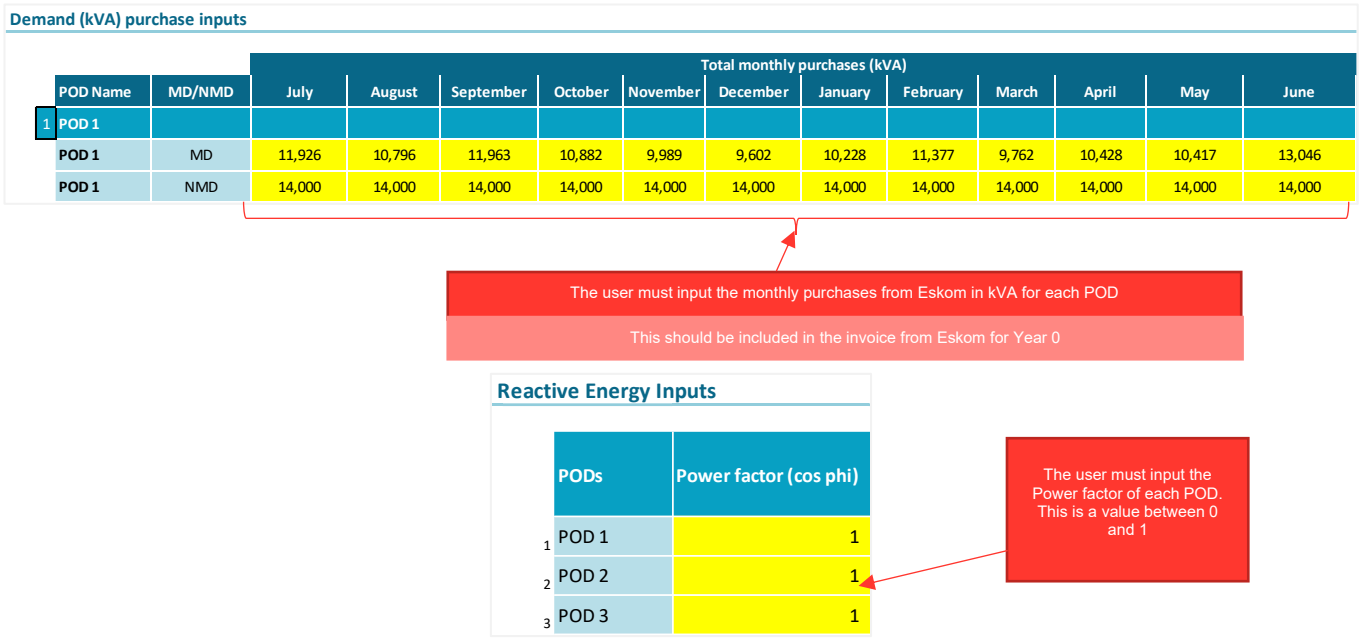
This step involves the user capturing the Eskom Purchase volumes for the various Points Of Delivery (PODs). Further, the power factor for each POD is also to be defined. The following figures highlight the required actions within this sheet.

Energy (kWh) purchase inputs

			Total monthly purchases (kWh)											
	POD Name	TOU period	July	August	September	October	November	December	January	February	March	April	May	June
1	**POD 1**													
	POD 1	OffPeak	1,817,242	2,076,415	1,863,725	1,929,780	1,908,066	2,007,897	2,038,248	1,747,023	1,871,352	2,008,535	2,043,265	1,920,032
	POD 1	Standard	1,994,374	1,933,786	1,840,103	1,882,596	1,808,798	1,775,574	1,755,654	1,721,596	1,896,564	1,709,300	1,904,532	1,938,762
	POD 1	Peak	874,581	793,938	802,423	764,777	755,425	727,525	675,324	719,714	770,375	706,686	785,458	862,307

The user must input the monthly purchases from Eskom in kWh for each POD

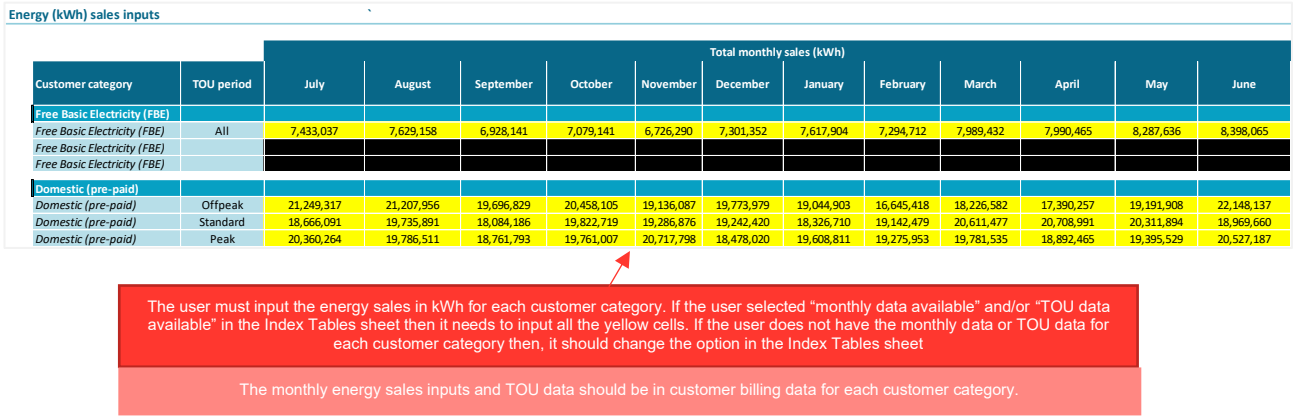
This should be included in invoices from Eskom for Year 0



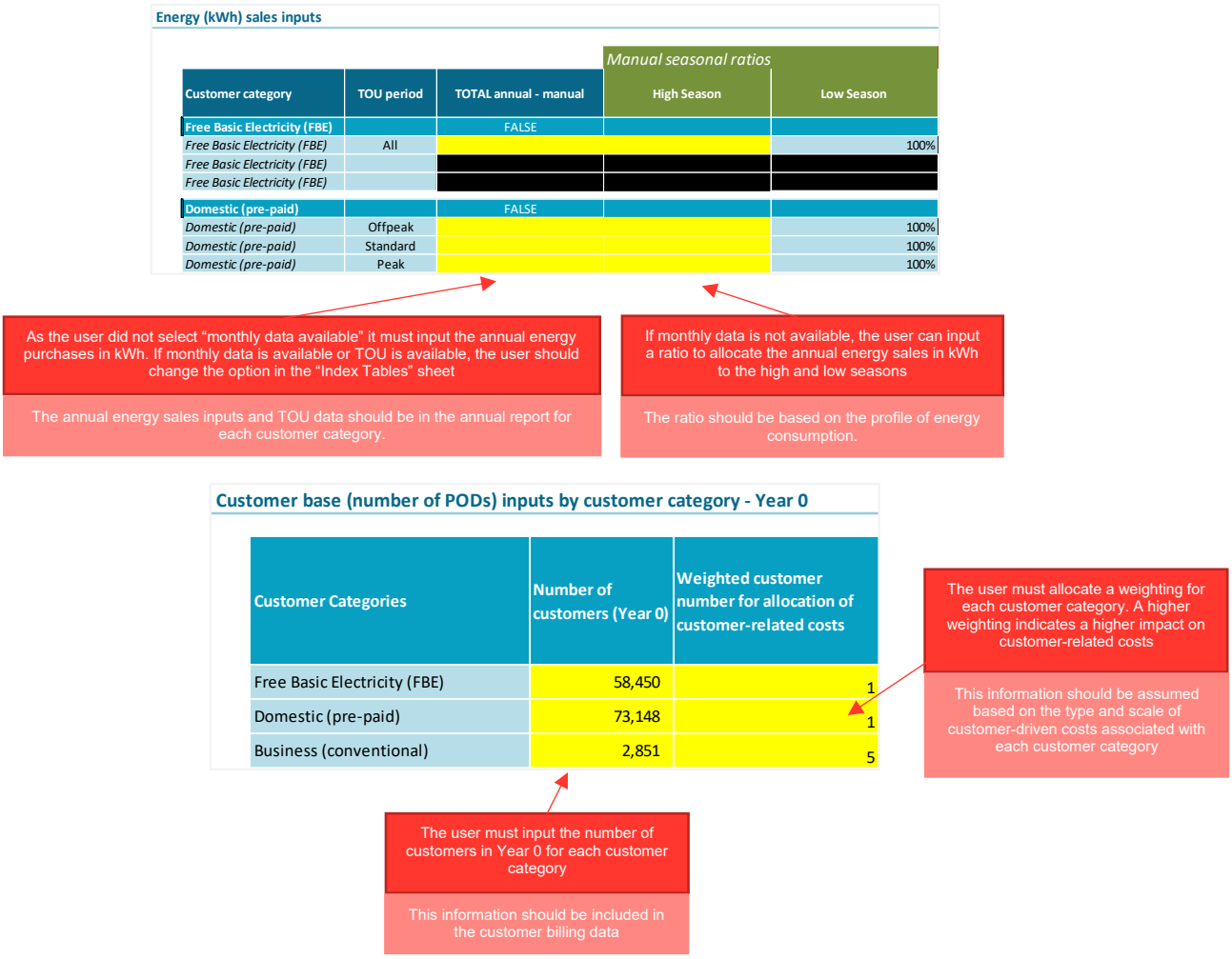
2.2.9 Capturing Commercial Inputs (Year 0)

The user is to capture energy sales inputs in kWh for the various customer categories over all months or per year depending on the methodology chosen in the “Index Tables” sheet. Further, the number of customers in each category is to be defined. The following figures highlight the required actions within this sheet.

The table below highlights what the user needs to input if monthly data is available and TOU data is available for the Domestic (pre-paid) customer category.



The table below highlights what the user needs to input if monthly data is not available, but annual TOU data is available for the Domestic (pre-paid) customer category.



Data entry note: Weighted customer number for allocation of customer-related costs

Weighted customer numbers are used in the cost allocation calculations to allocate customer-related costs between customer categories. They provide a proxy for the relative cost of serving each customer category where customer-related costs cannot be directly identified or attributed from the municipality's accounting records.

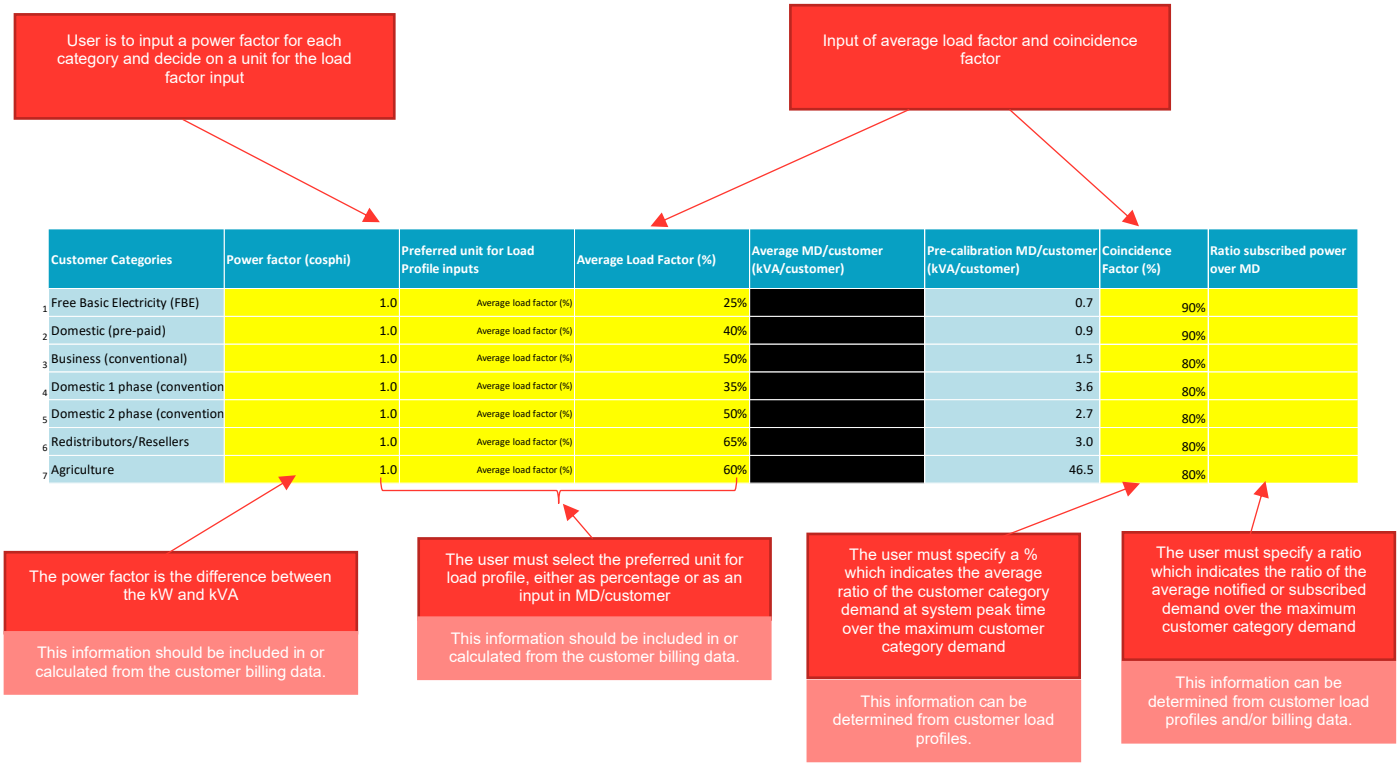
The weighting should reflect the relative level of effort, systems requirements and cost intensity associated with serving different customer categories. Relevant factors may include the complexity of the metering and billing arrangements, the frequency and complexity of customer queries, account management requirements, vending or prepaid support requirements, credit control and revenue protection activities, and whether dedicated staff or specialised processes are required for particular customer groups.

Where a municipality has undertaken a detailed customer service, billing or cost allocation study, the weightings should be based on that evidence. Where such information is not available, reasonable estimates may be used, provided the assumptions are transparent and consistently applied. A higher weighting indicates that a customer category is expected to impose a higher customer-related cost burden on the municipality and will therefore receive a larger allocation of customer-driven costs.

The original methodology was informed by Eskom's CTS approach and the reference weightings used in Eskom's CTS reporting. These reference values may provide a useful starting point where municipality-specific evidence is not available, but they should not be treated as automatically applicable. The user should review the weightings against the municipality's own customer categories, service arrangements and available data, and should update them where more representative information is available.

2.2.10 Capturing Technical Inputs (Years 1 – 4)

The user is to capture technical inputs to assess the demand constraints and allocate demand-driven costs to each customer category. The following figures highlight the required actions within this sheet.



Data entry note: Load profile , maximum demand and coincidence factor inputs

The load profile inputs are used to estimate how each customer category contributes to system demand and, consequently, how demand-driven costs are allocated between customer categories. These inputs are important because demand-driven costs are caused not only by the total amount of electricity consumed, but also by the level and timing of demand placed on the network.

Average load factor and maximum demand

- The maximum demand (MD) for each customer category may be derived using either an average load factor or an average MD per customer, depending on the data available to the municipality. These inputs are used to estimate each customer category's contribution to peak demand and to allocate demand-related costs between customer categories.
- The average load factor represents the ratio of average demand to maximum demand for a customer category over the relevant period. A lower load factor indicates that consumption is more concentrated in peak periods, while a higher load factor indicates that consumption is more evenly spread over time. If this information is available, the user can enter the average load factor for each customer category and the model will use it, together with sales and customer number inputs, to estimate the average MD per customer. The load factor should be based on representative load profile or interval metering data where possible.
- Alternatively, the user may enter the average MD per customer directly by selecting the appropriate load profile input unit. This approach may be preferable where MD information is available from customer billing data, metering records or demand studies. Where average MD

per customer is entered directly, the user should ensure that the values are consistent with the sales, customer numbers and voltage-level assumptions used elsewhere in the model.

- Where measured load profile data is not available, reasonable assumptions may be used. These assumptions should be documented and should be reviewed for reasonableness against comparable customer categories, historic demand data, Eskom billing information, or other available municipal planning data.

Coincidence factor

- The coincidence factor represents the proportion of a customer category's maximum demand that occurs at the time of the overall system peak. It is used to estimate the coincident peak demand contribution of each customer category and therefore supports the allocation of demand-related costs on a cost-causation basis.
- This input is important because a customer category with a high individual maximum demand does not necessarily impose the same level of cost on the system if its peak demand occurs at a different time from the municipal system peak. Conversely, a customer category whose demand is closely aligned with the system peak will generally receive a larger allocation of demand-driven costs.
- A higher coincidence factor indicates that a customer category's demand is more closely aligned with the system peak and will therefore receive a larger share of demand-related costs. The factor should be based on representative load profile or interval metering data where possible. Where such data is not available, the user should apply a transparent and reasonable assumption, taking into account the expected usage pattern of the customer category. For example, residential customers may have a relatively high coincidence factor where their evening peak demand coincides with the municipality's system peak , while some industrial or commercial customers may have lower coincidence depending on their operating hours and load characteristics.

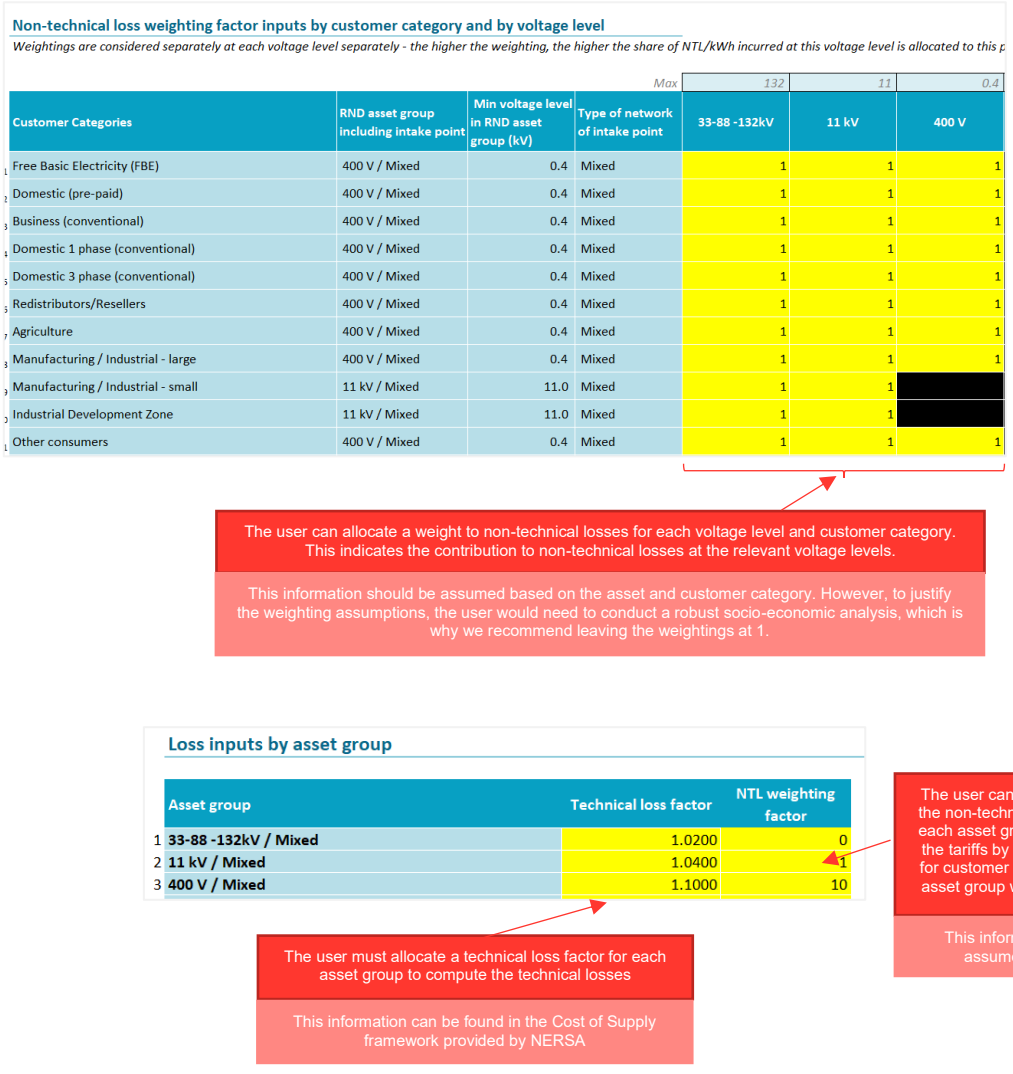
Ratio of subscribed power to maximum demand

- This is an optional input. The ratio of subscribed, notified or contracted demand to maximum demand represents the relationship between the demand capacity reserved for a customer category and the demand actually expected to be used by that category.
- This input is relevant where the tariff design includes a capacity-based or notified maximum demand charge. The model uses this ratio to estimate the average subscribed or notified demand for each customer category from the calculated maximum demand. This value may then be used to determine R/kVA demand-related charges where these are selected in the rate design dashboard.
- The ratio should be reviewed for reasonableness, particularly where contracted capacity is materially higher than actual demand, where customers frequently exceed their notified demand and whether the assumed ratio is consistent with the municipality’s tariff rules, customer agreements, billing records or demand management practices.
- Where municipality-specific evidence is not available, the user may apply a reasonable assumption, but this should be clearly documented because it may affect both the allocation of demand-driven costs and the level of any capacity-based charges proposed through the model.

Calculation note: How are demand driven costs allocated?

The model allocates demand-driven costs to customer categories using the Average and Excess methodology. Demand-driven costs are costs that are caused by the need to provide sufficient network and supply capacity to meet customer demand, particularly during periods of high or peak usage.

- Under the Average and Excess methodology, customer demand is separated into an average component and an excess component. The average component reflects the ongoing level of demand implied by a customer category's annual energy consumption, while the excess component reflects the additional demand above that average level that the system must be able to accommodate.
- This approach recognises that part of the demand-related cost is associated with serving customers' general level of use, while the remainder is associated with the additional capacity required to meet their maximum demand. The model therefore allocates the average portion of demand-related costs using average demand, and allocates the excess portion using the additional demand above the average level.
- The objective is to allocate demand-driven costs in a way that reflects cost causation. Customer categories with higher maximum demand, or with demand that is more closely aligned to the system peak, will generally receive a larger allocation of demand-related costs.



Non-technical loss weighting factor inputs by customer category and by voltage level

Weightings are considered separately at each voltage level separately - the higher the weighting, the higher the share of NTL/kWh incurred at this voltage level is allocated to this p

				Max	132	11	0.4
	Customer Categories	RND asset group including intake point	Min voltage level in RND asset group (kV)	Type of network of intake point	33-88 -132kV	11 kV	400 V
1	Free Basic Electricity (FBE)	400 V / Mixed	0.4	Mixed	1	1	1
2	Domestic (pre-paid)	400 V / Mixed	0.4	Mixed	1	1	1
3	Business (conventional)	400 V / Mixed	0.4	Mixed	1	1	1
4	Domestic 1 phase (conventional)	400 V / Mixed	0.4	Mixed	1	1	1
5	Domestic 3 phase (conventional)	400 V / Mixed	0.4	Mixed	1	1	1
6	Redistributors/Resellers	400 V / Mixed	0.4	Mixed	1	1	1
7	Agriculture	400 V / Mixed	0.4	Mixed	1	1	1
8	Manufacturing / Industrial - large	400 V / Mixed	0.4	Mixed	1	1	1
9	Manufacturing / Industrial - small	11 kV / Mixed	11.0	Mixed	1	1	
10	Industrial Development Zone	11 kV / Mixed	11.0	Mixed	1	1	
11	Other consumers	400 V / Mixed	0.4	Mixed	1	1	1

Loss inputs by asset group

	Asset group	Technical loss factor	NTL weighting factor
1	33-88 -132kV / Mixed	1.0200	0
2	11 kV / Mixed	1.0400	1
3	400 V / Mixed	1.1000	10

Data entry note: Technical and non-technical losses

Technical Losses

Technical losses are the physical energy losses that occur as electricity is transported through the network. These losses arise from the inherent electrical characteristics of network assets, including conductor resistance, transformer losses, service cable losses and other equipment-related losses.

Technical losses are therefore linked to the network configuration, voltage level, length and type of lines and cables, transformer loading, and the level and pattern of demand on the network.

- The user should enter technical loss factors for each applicable voltage level based on the best available engineering evidence. The municipality's planning, network or operations engineers should be consulted when determining these inputs. Where available, the inputs should be supported by network studies, load-flow analysis, technical loss studies, reduced network diagrams, transformer and feeder data, or other engineering assessments.
- Technical losses are usually better understood for the high-voltage and medium-voltage parts of the network, where network information and metering data may be more complete. For low-voltage networks, the values may need to be estimated using representative feeder information, typical conductor lengths, transformer loading assumptions, customer density, and engineering judgement. Where technical loss factors are estimated rather than measured, the assumptions should be documented and reviewed for reasonableness against the municipality's overall loss position and any reference values provided in the COS Framework.
- The technical loss factors entered in the model are used to estimate the physical losses associated with supplying customers at different voltage levels. Customers supplied at lower voltage levels generally attract cumulative upstream losses because electricity must pass through more parts of the network before reaching the customer connection point.

Non-technical Losses

Non-technical losses (NTL) are losses that are not caused by the physical characteristics of the network. They may arise from unauthorised connections, meter tampering, faulty or inaccurate meters, unmetered supplies, billing errors, data handling errors, incorrect customer classification, unbilled consumption or theft of electricity. These losses may also be referred to as commercial losses.

- In the model, non-technical losses are allocated using weighting factors by customer category and voltage level. The table titled "Non-technical loss weighting factor inputs by customer category and by voltage level" allows the user to indicate which customer categories and voltage levels are expected to contribute to non-technical losses. A non-zero weighting indicates that the relevant customer category is assumed to contribute to non-technical losses at that voltage level. Higher weighting factors indicate a higher assumed contribution to non-technical losses relative to other customer categories or voltage levels.
- These weighting factors should be based on the municipality's available evidence, such as revenue protection information, meter audit results, tamper reports, illegal connection records, billing data analysis, feeder-level energy balances, customer inspections, or operational knowledge of areas where losses are concentrated. Where precise data is not available, the user may apply reasonable assumptions, but these should be transparent, documented and consistently applied.
- The user must also allocate a global non-technical loss weighting factor for each voltage level. This indicates where non-technical losses are expected to occur on the network and the relative distribution of these losses across voltage levels. This is important because non-technical losses are not always evenly distributed across the network or customer base.
- The user should ensure that the selected non-technical loss weightings are consistent with the total loss position implied by electricity purchases and sales, the technical loss factors entered in the model, and any known loss-reduction targets or revenue protection initiatives. Where the model derives non-technical losses as the residual difference between total losses and estimated technical losses, unrealistic technical loss assumptions may materially affect the

calculated non-technical loss result. The technical and non-technical loss inputs should therefore be reviewed together before relying on the COS outputs.

Calculation note: How are total losses calculated in the tool?

- The model calculates total losses by first estimating the technical losses associated with each voltage level and customer category, and then deriving non-technical losses as the difference between total system losses and calculated technical losses.
- Technical losses are estimated using the technical loss factors applicable to each part of the network used to supply a customer category. For example, customers supplied at lower voltage levels are allocated the cumulative losses associated with the upstream network assets used to serve them. The model uses these technical loss factors, together with customer sales data, to estimate the technical energy losses attributable to each customer category and network asset group.
- Non-technical losses are then calculated as the residual difference between total losses and total technical losses. These residual losses are allocated across customer categories and network asset groups using the non-technical loss weighting factors set in the model. This allows the user to reflect, where known, which customer categories or areas are more likely to contribute to non-technical losses.
- The model then combines technical and non-technical losses to determine the total energy losses and total energy requirement for each customer category and network asset group. These total loss factors are used in the COS calculation to allocate the cost of losses and ensure that the cost to serve each customer category reflects both the physical losses on the network and the estimated non-technical losses.



Data entry note: Demand calibration inputs

Loss load factor

The loss load factor is used to convert annual energy losses (in MWh) into an estimate of demand losses (in MW) at the time of peak demand. This is necessary because technical losses are partly driven by current flow and therefore vary with loading conditions. Losses during peak demand periods may differ from average losses over the year.

The user defines the loss load factor by entering an average k-factor. The k-factor is used to estimate the relationship between energy loss factors, expressed as a percentage of energy purchases, and demand loss factors, expressed as a percentage of maximum demand. In practical terms, it helps the model estimate how much of the system peak demand is attributable to losses rather than customer consumption.

The k-factor may be derived from an empirical loss load factor formula. An empirical formula is based on observed data or industry practice rather than being calculated directly from first engineering principles. The selected k-factor should be reviewed for reasonableness against the municipality's network characteristics, load profile, technical loss assumptions and any available engineering studies. If municipality-specific evidence is not available, the user may apply a reasonable assumption, but this should be documented because it affects the allocation of demand-driven losses and, therefore, demand-related costs.

Demand scaling adjustments

The demand scaling adjustment inputs are used to calibrate the model's estimate of system peak demand. This calibration is important because customer-level load factors, customer numbers and sales data may produce a bottom-up estimate of peak demand that differs from the municipality's known or measured system peak demand.

- **Top-down estimated peak demand:** This is the user-entered estimate of the municipality's total system peak demand, where this value is known. It should preferably be based on measured maximum demand from Eskom bills, system metering, SCADA data, bulk supply meters, network studies or other reliable demand records. Where a top-down estimate is entered, it provides an external reference point against which the model can calibrate the bottom-up demand calculation.
- **Peak demand calculated bottom-up approach (Year 0):** This is the peak demand calculated by the model from customer category inputs. The model uses customer sales, customer numbers and load profile assumptions to estimate the maximum demand for each customer category. These customer category estimates are then aggregated to produce a bottom-up estimate of total system peak demand. This result is useful where measured system peak demand is not available, but it is sensitive to the quality of the load factor, average maximum demand and coincidence factor inputs.
- **Maximum "failsafe" peak demand (Year 0):** The failsafe peak demand is a reasonableness limit calculated using total energy requirements and the maximum system load factor entered in the Methodology Inputs sheet. It represents an upper-bound check on the system peak demand that would be implied by the annual energy requirement and the maximum plausible load factor. This is not intended to replace measured demand data, but to prevent the model from using a peak demand value that appears physically implausible or inconsistent with the annual energy requirement.
- **Activated peak demand (Year 0):** The activated peak demand is the demand value ultimately used by the model in the demand-related calculations. The model compares the available top-down estimate and the bottom-up calculated peak demand against the failsafe peak demand. If the top-down or bottom-up value is within the failsafe limit, the model uses the appropriate value in the demand calculations. If the selected estimate exceeds the failsafe limit, the model uses the failsafe value to avoid overstating demand-driven costs. The activated peak demand should therefore be reviewed to confirm that the value used by the model is reasonable and consistent with the municipality's known demand profile. If there is a large discrepancy between the failsafe peak demand and the bottom-up calculated peak demand, the user should verify the technical inputs for each customer category, customer base numbers, and sales data included in the model.
- **Bypass calibration:** This option allows the user to bypass the demand calibration process and use the model's calculated demand values without applying the top-down or failsafe calibration adjustment. This may be appropriate where the user has confidence in the bottom-up load profile inputs and does not want the model to adjust the calculated demand to align with a top-down estimate or failsafe limit. However, bypassing calibration should only be done where the underlying sales, customer number, load factor, maximum demand and coincidence factor inputs have been reviewed and are considered reliable. If calibration is bypassed when the input data is incomplete or inconsistent, the model may produce demand allocations that are not representative of the municipality's actual system peak demand.

2.2.11 Capturing Commercial Inputs (Years 1 - 4)

The user is to capture the expected increase in kWh sales to all customer categories along with potential growth in customer numbers. Further, the user is to determine the year-on-year NTL % reduction. The following figures highlight the required actions within this sheet.

Commercial inputs by customer category - Sales growth forecasts

			Inputs							
		Year:	1	1	2	2	3	3	4	4
		Methodology selection:	0	0	0	0	1	1	1	1
	Customer Categories	Year 0 estimate (kWh)	Year 1 estimate (kWh)		Year 2 estimate (kWh)			Year 3 estimate (% increase)		Year 4 estimate (% increase)
1	Free Basic Electricity (FBE)	90,675,333	100,000,524		100,000,524			1%		1%
2	Domestic (pre-paid)	234,169,478	242,512,321		242,512,321			1%		1%
3	Business (conventional)	18,930,526	19,542,638		19,542,638			0%		0%

Based on the chosen methodology, the user must input the forecasted sales for each customer category either in kWh or as a percentage increase year-on-year.

The information should be included in the sales projections of the utility

Commercial inputs by customer category - customer base forecasts

			Inputs							
		Year:	1	1	2	2	3	3	4	4
		Methodology selection:	0	0	0	0	1	1	1	1
	Customer Categories	Year 0 estimate (#)	Year 1 estimate (#)		Year 2 estimate (#)			Year 3 estimate (% increase)		Year 4 estimate (% increase)
1	Free Basic Electricity (FBE)	58,450	61,211		61,452			5%		0%
2	Domestic (pre-paid)	73,148	74,200		74,550			5%		0%
3	Business (conventional)	2,851	3,001		3,151			0%		0%

Based on the chosen methodology, the user must input the forecasted number of customers for each customer category either in hardcoded figures or as a percentage increase year-on-year.

The information should be included in the customer base projections of the utility

Non-technical losses - future outlook

NTL reduction	
Year on year NTL reduction %	0.0% (as a % of Year 0 NTL)
Year 0 to Year 2 reduction	0%

The user must input the year-on-year Non-Technical-Losses reduction based on the NTL in Year 0

The information should be included in the business plan of the utility

2.2.12 Capturing Financial Inputs (Years 1 – 4)

The user is to capture multi-year inputs relating to OPEX and other revenues. Further, inputs relating to future capital investment are also to be captured. The following figures highlight the required actions within this sheet.

OPEX inputs (non purchase)

		Inputs							
	Year:	1	1	2	2	3	3	4	4
	Methodology selection:	1	0	1	0	1	0	0	1
	Year 0 estimate (Rand)	Year 1 estimate (Rand)		Year 2 estimate (Rand)		Year 3 estimate (Rand)			Year 4 estimate (nominal % increase)
Network OPEX	R 191,163,581	R 195,988,852		R 202,786,328	R -	R 232,158,411	R -	R -	R -
Salaries and allowances	R 91,826,876	R 94,665,413		R 97,409,950		R 118,810,989			0%
Contracted Services	R 1,404,477	R 1,432,567		R 1,489,870		R 671,448			0%
Materials and supplies	R 2,297,263	R 2,343,208		R 2,436,937		R 10,505,410			0%

Based on the chosen methodology, the user must input the forecasted amount of OPEX for each OPEX item either in hardcoded figures or as a percentage increase year-on-year.

The information should be included in the financial budgets of the utility

Non-electricity supply revenues *(will be netted out of OPEX)*

	Year 0 estimate	Year 1 estimate (Rand)		Year 2 estimate (Rand)		Year 3 estimate (Rand)			Year 4 estimate (nominal % increase)
Other revenues									
Recon disconnect/Recon fees	R 1,927,256	R 1,965,801		R 2,044,433		R 7,744,304			0%
Service connections	R 1,472,703	R 1,456,257		R 1,514,507		R 19,594			0%
Meter reading fees	R 6,336	R 6,493		R 6,753		R 19,594			0%

Based on the chosen methodology, the user must input the forecasted amount of non-electricity supply revenues for each revenue category either in hardcoded figure or as a percentage increase year-on-year

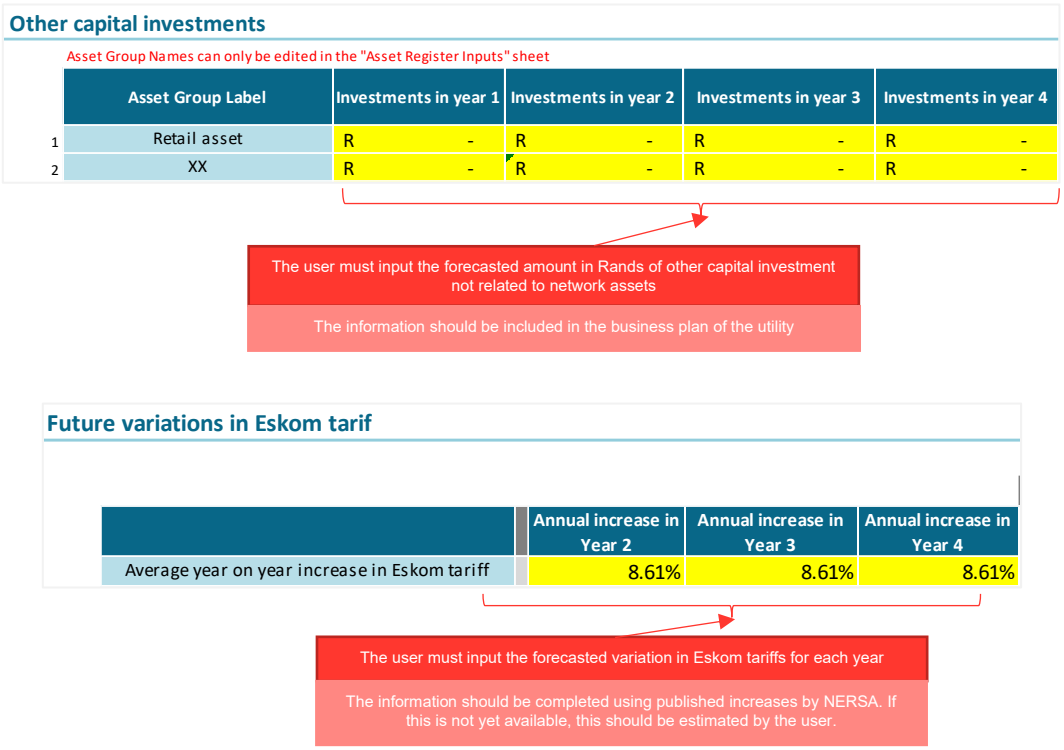
The information should be included in the financial budgets of the utility

New core network capital investments

	Asset Group Label	Investments in year 1	Investments in year 2	Investments in year 3	Investments in year 4
1	33 - 88 - 132 kV / Urban	R 21,141,641	R 21,856,120	R 22,511,803	R 23,187,157
2	11 kV / Mixed	R 52,854,102	R 54,640,299	R 56,279,508	R 57,967,894
3	400 V / Mixed	R 17,924,435	R 18,530,188	R 19,086,094	R 19,658,677

The user must input the forecasted amount in Rands of network capital investment for each voltage level year-on-year

The information should be included in the business plan of the utility



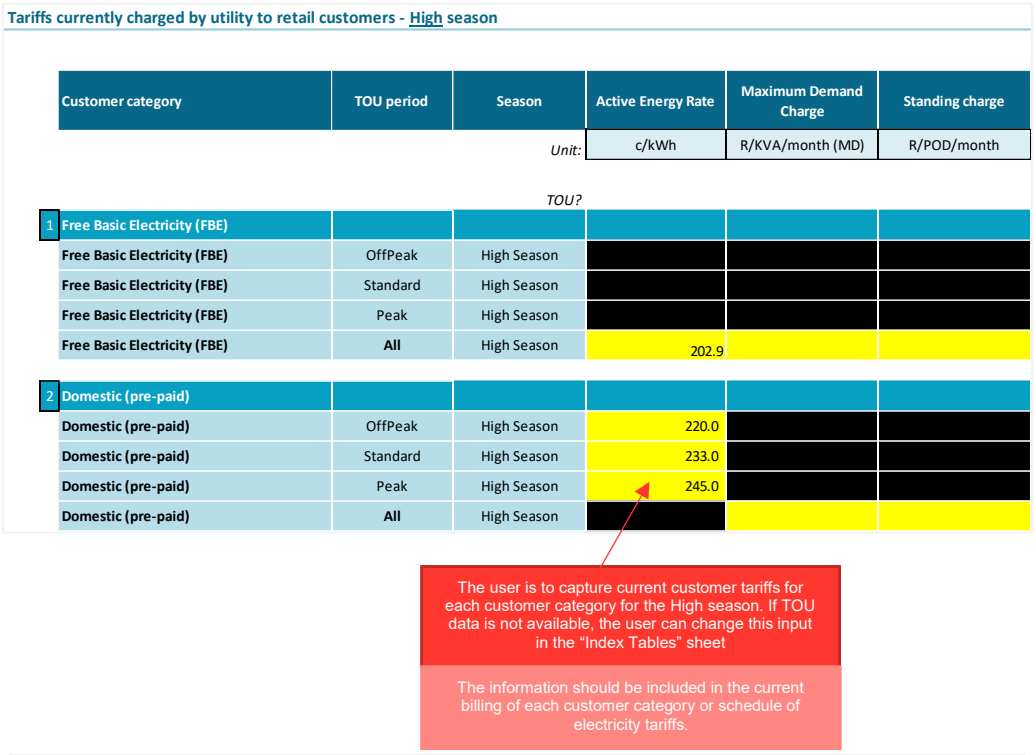
Calculation note: How are Eskom annual increases applied in the tool?

- Eskom annual increases are used in the model to forecast Eskom purchase costs for the future study years. The user-entered increase is applied to the Eskom tariff inputs to estimate the cost of electricity purchases in the forecast period, including the Year 2 period for which tariffs are designed.
- The Eskom annual increase input should be understood as a weighted average increase for the relevant Eskom tariffs, rather than necessarily a uniform increase applied to every Eskom charge component. This is important because Eskom tariff increases are not always applied evenly across energy, demand and fixed charge components. For example, the energy charge may increase by one percentage, while network demand, ancillary, service or administration-related charges may increase by a different percentage.
- Where the Eskom tariff increase differs by charge component, the user should calculate an equivalent weighted average increase before entering the value in the model. This weighted average should be based on the municipality's expected Eskom billing mix, taking account of the relative contribution of energy charges, demand charges and fixed charges to the total Eskom bill. In practical terms, the user should estimate the overall percentage increase in the total Eskom purchase cost that would result after applying the component-specific Eskom increases to the relevant tariff components.
- This approach addresses the concern that the model uses a single Eskom annual increase input, even though Eskom's approved tariff adjustments may vary between energy and non-energy components. By entering the equivalent weighted average increase, the model captures the overall financial effect of the differentiated Eskom tariff adjustments on the municipality's total Eskom purchase cost. This allows the forecast purchase cost included in the revenue requirement to remain representative, without requiring the model to separately project each Eskom charge component.
- Where detailed Eskom tariff component data is available, the user should use the Eskom tariff inputs and Eskom purchase volume inputs to support the weighted average calculation. The assumptions used to derive the weighted average increase should be documented, particularly

where non-energy charge components increase at materially different rates from energy charges.

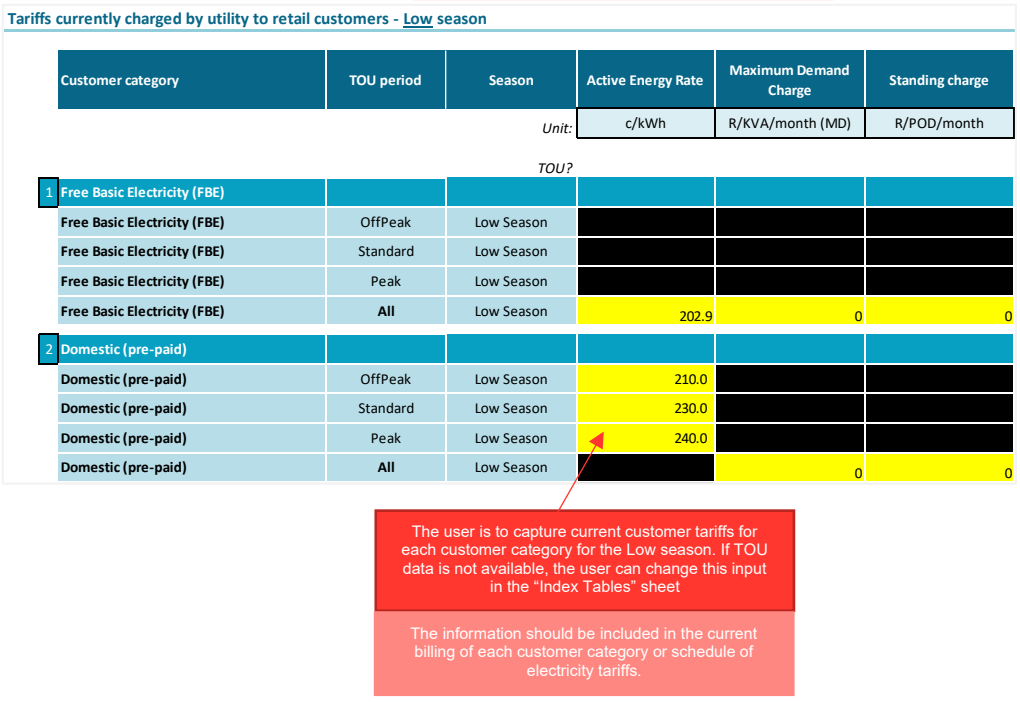
2.2.13 End-User Tariffs Inputs (Year 1)

The user is expected to capture the tariffs that are currently applied to each customer category during the High and Low seasons. The following figures highlight the required actions within this sheet.



Tariffs currently charged by utility to retail customers - High season

	Customer category	TOU period	Season	Active Energy Rate	Maximum Demand Charge	Standing charge
			Unit:	c/kWh	R/KVA/month (MD)	R/POD/month
			TOU?			
1	Free Basic Electricity (FBE)					
	Free Basic Electricity (FBE)	OffPeak	High Season			
	Free Basic Electricity (FBE)	Standard	High Season			
	Free Basic Electricity (FBE)	Peak	High Season			
	Free Basic Electricity (FBE)	All	High Season	202.9		
2	Domestic (pre-paid)					
	Domestic (pre-paid)	OffPeak	High Season	220.0		
	Domestic (pre-paid)	Standard	High Season	233.0		
	Domestic (pre-paid)	Peak	High Season	245.0		
	Domestic (pre-paid)	All	High Season			



Tariffs currently charged by utility to retail customers - Low season

	Customer category	TOU period	Season	Active Energy Rate	Maximum Demand Charge	Standing charge
			Unit:	c/kWh	R/KVA/month (MD)	R/POD/month
			TOU?			
1	Free Basic Electricity (FBE)					
	Free Basic Electricity (FBE)	OffPeak	Low Season			
	Free Basic Electricity (FBE)	Standard	Low Season			
	Free Basic Electricity (FBE)	Peak	Low Season			
	Free Basic Electricity (FBE)	All	Low Season	202.9	0	0
2	Domestic (pre-paid)					
	Domestic (pre-paid)	OffPeak	Low Season	210.0		
	Domestic (pre-paid)	Standard	Low Season	230.0		
	Domestic (pre-paid)	Peak	Low Season	240.0		
	Domestic (pre-paid)	All	Low Season		0	0

2.2.14 Eskom Tariff Inputs (Year 1)

The user is expected to capture current the Eskom tariffs that apply to each POD during the High and Low seasons. This can be done manually as detailed below or using the “Eskom rates add-on” as mentioned in Section **Error! Reference source not found.**. Please refer to the “Eskom rates add-on” training video embedded in Section **Error! Reference source not found.** for more information on this. The following figures highlight the required actions within this sheet.

Eskom Purchase Tariff Inputs by POD - High Season

	POD	TOU period	Season	Active energy charge	Transmission network charge	Distribution network charge	Ancillary service charge	Administration charge	Reactive energy charge	Low voltage subsidy charge	Electrification subsidy charge
			Unit:	c/kWh	R/KVA/month (NMD)	R/KVA/month (NMD)	c/kWh	R/POD/day	c/KVArh	c/KVA/month (NMD	c/kWh
			TOU?	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
1	POD 1										
	POD 1	OffPeak	High Season	65.23							
	POD 1	Standard	High Season	120.16							
	POD 1	Peak	High Season	396.57							
	POD 1	All	High Season		13.82	0	0.48	173.57	19.51	19.5	10.8
2	POD 2										
	POD 2	OffPeak	High Season	65.23							
	POD 2	Standard	High Season	120.16							
	POD 2	Peak	High Season	396.57							
	POD 2	All	High Season		13.82	0	0.48	173.57	19.51	19.5	10.8

The user is to capture current Eskom tariffs for each POD for the High season. If TOU data is not available, the user can change this input in the “Index Tables” sheet.

The information should be included in the current billing from Eskom for each POD.

Eskom Purchase Tariff Inputs by POD - Low Season

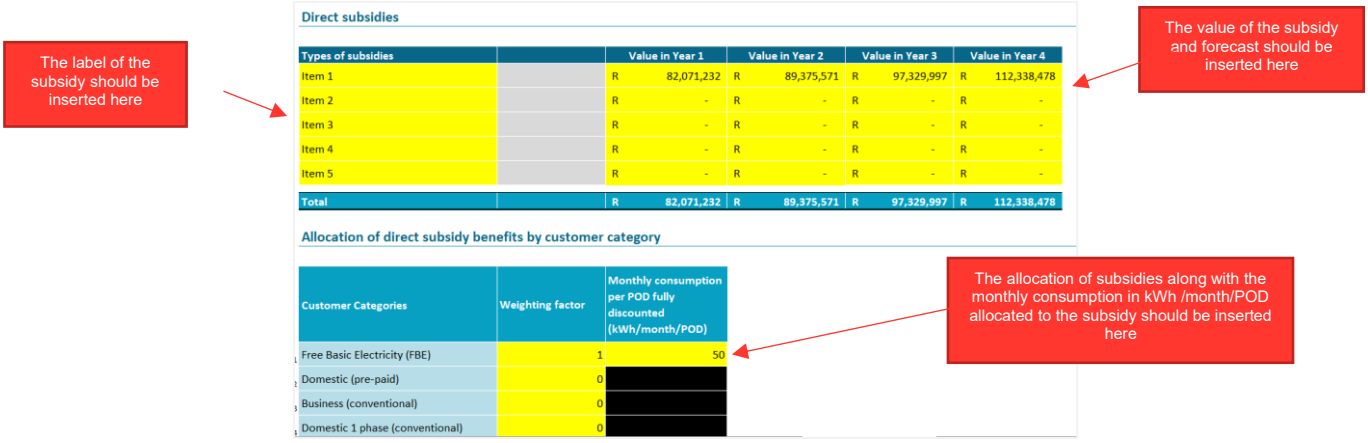
	POD	TOU period	Season	Active energy charge	Transmission network charge	Distribution network charge	Ancillary service charge	Administration charge	Reactive energy charge	Low voltage subsidy charge	Electrification subsidy charge
			Unit:	c/kWh	R/KVA/month (NMD)	R/KVA/month (NMD)	c/kWh	R/POD/day	c/KVArh	c/KVA/month (NMD	c/kWh
			TOU?	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
1	POD 1										
	POD 1	OffPeak	Low Season	56.47							
	POD 1	Standard	Low Season	89.05							
	POD 1	Peak	Low Season	129.34							
	POD 1	All	Low Season		13.82	0	0.48	173.57	19.51	19.5	10.8
2	POD 2										
	POD 2	OffPeak	Low Season	56.47							
	POD 2	Standard	Low Season	89.05							
	POD 2	Peak	Low Season	129.34							
	POD 2	All	Low Season		13.82	0	0.48	173.57	19.51	19.5	10.8

The user is to capture current Eskom tariffs for each POD for the Low season. If TOU data is not available, the user can change this input in the “Index Tables” sheet.

The information should be included in the current billing from Eskom for each POD.

2.2.15 FBE Inputs

The user is to capture information relating to subsidies for the various years and how these subsidies are allocated to different customer categories. The following figures highlight the required actions within this sheet.



Direct subsidies

Types of subsidies		Value in Year 1	Value in Year 2	Value in Year 3	Value in Year 4
Item 1		R 82,071,232	R 89,375,571	R 97,329,997	R 112,338,478
Item 2		R -	R -	R -	R -
Item 3		R -	R -	R -	R -
Item 4		R -	R -	R -	R -
Item 5		R -	R -	R -	R -
Total		R 82,071,232	R 89,375,571	R 97,329,997	R 112,338,478

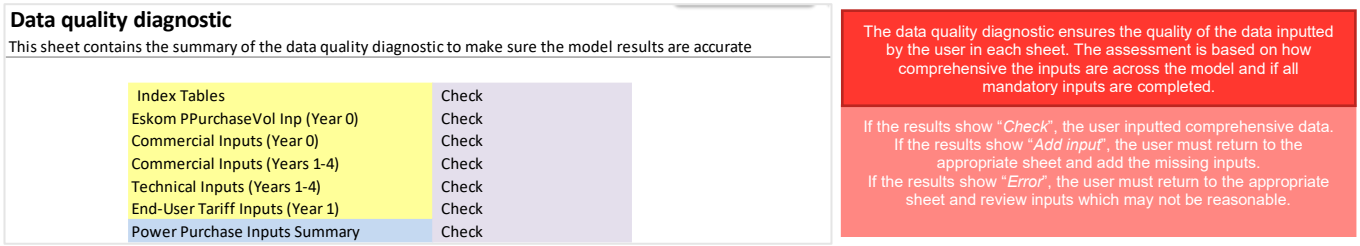
Allocation of direct subsidy benefits by customer category

Customer Categories	Weighting factor	Monthly consumption per POD fully discounted (kWh/month/POD)
Free Basic Electricity (FBE)	1	50
Domestic (pre-paid)	0	
Business (conventional)	0	
Domestic 1 phase (conventional)	0	

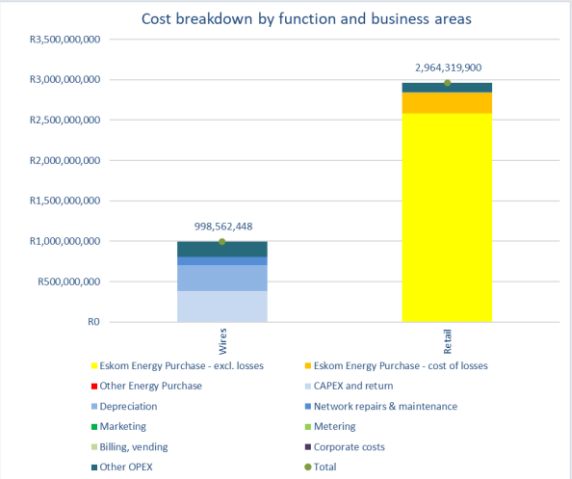
2.3 USE CASE 2: VALIDATING INPUTS AND NAVIGATING COS STUDY RESULTS

The following Use Case highlights how the user can ensure the quality of the data inputted into the model and view the results of the COS study. This step is essential to ensure the quality of the COS results before defining the tariffs.

In the "***Data quality diagnostic***" sheet, the user can verify if all mandatory inputs have been correctly entered into the model.

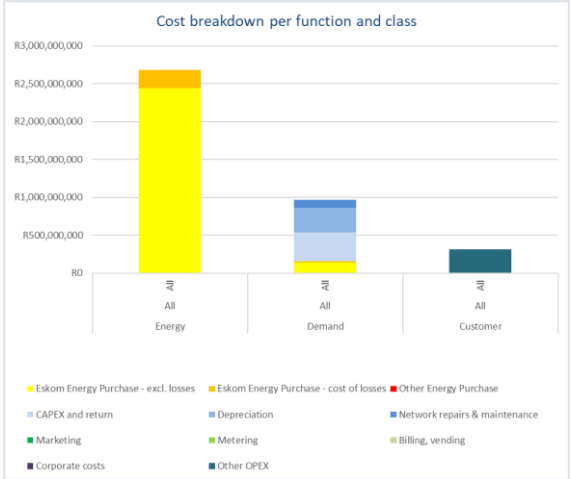


After reviewing the data quality diagnostics, to view the results of the COS analysis, the user must refer to the sheet titled *"**COS Results (Year 2)**"* and *"**Summary Charts (Year 2)**"*. The "***COS Results (Year 2)***" sheet highlights the COS results in a table format including the cost-reflective charges by function, business area, class, season, and TOU for each customer category. The first section of the *"**Summary Charts (Year 2)**"* sheet illustrates the COS results in a visual representation, which is detailed below.



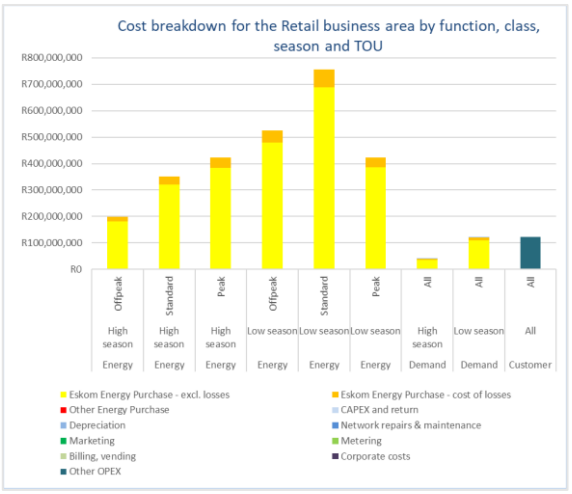
The figure shows the cost breakdown by function for both business areas. Due to the nature of each business, cost functions are different. All costs related to the infrastructure are allocated to the Wires business unit, and all costs related to the sale of the energy are allocated to the Retail business area

These results are based on inputs from the user (see how to allocate costs to functions in Use Case 1)



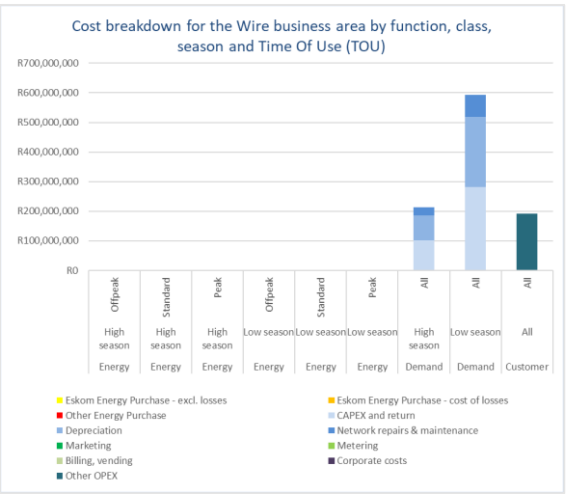
This figure shows the cost breakdown per class and function. Energy-driven costs vary with energy consumption, Demand-driven costs vary with the system peak demand, and Fixed costs vary by the type of customer served.

These results are based on inputs from the user (see how to allocate costs to classes in Use Case 1)



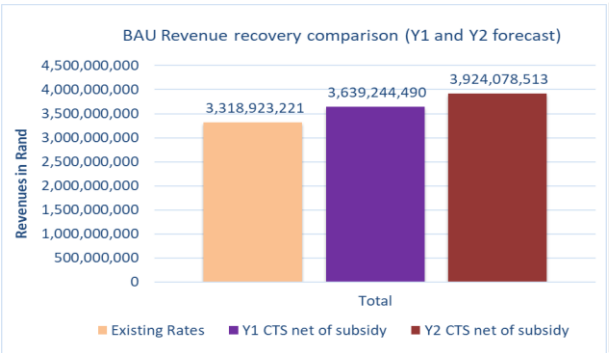
The figure shows the cost breakdown for the Retail business area by function, class, season, and TOU. Only the functions related to retail activities are shown in this graph. Due to the nature of the business area, most costs are energy-driven.

These results are based on inputs from the user (see how to allocate costs to class in Use Case 1).



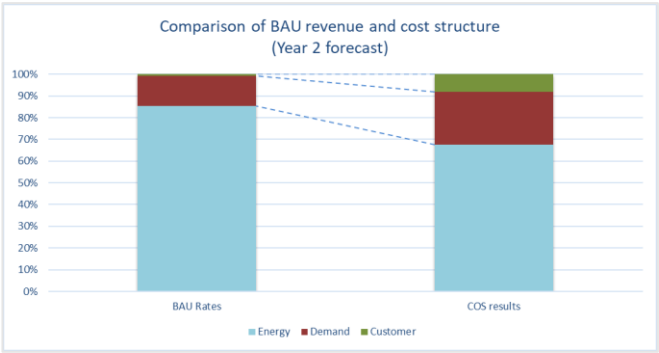
The figure shows the cost breakdown for the Wires business area by function, class, season, and TOU. Only functions related to the wires activities are shown in this graph. Due to the nature of the business area, costs are only demand and fixed driven.

These results are based on inputs from the user (see how to allocate costs to class in Use Case 1).



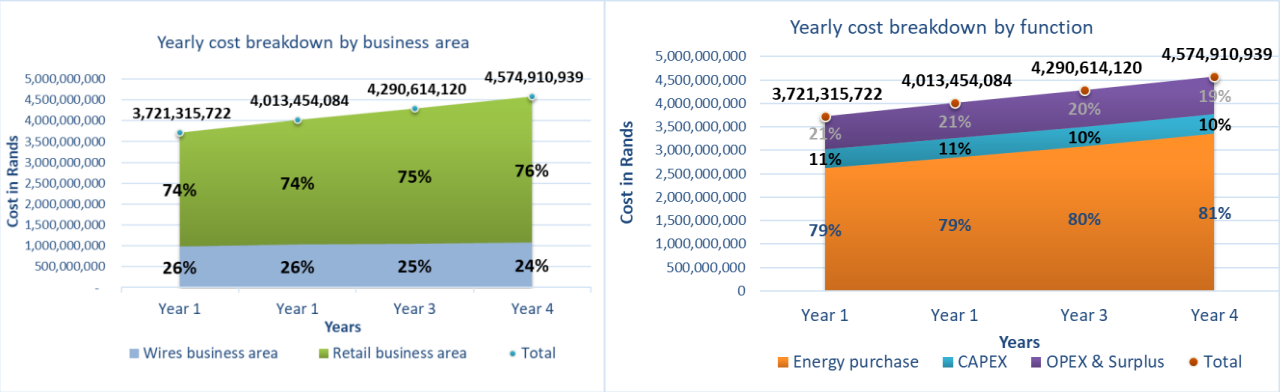
This figure compares current revenues with existing rates (Business-as-usual) and the revenue required to recover all the costs following the COS analysis for Year 1 and Year 2. In this example, the current tariffs are not recovering all costs.

These results are based on inputs from the user (see how to input data in the model in Use Case 1)



This figure compares the current revenue (BAU) structure and the cost structure computed by the COS study. The current revenue (BAU) structure is based on the existing tariff's structure (energy, demand and fixed). The cost structure computed by the COS study shows the "ideal" cost structure based on user inputs. A mismatch in the revenue and cost structures means that the current tariffs are not cost-reflective, which will negatively impact the financial stability of the municipality.

These results are based on inputs from the user (see how to classify costs in the model in Use Case 1)



These figures show the yearly cost breakdown by business area and by function. "*Year 0*" refers to the last year when datasets were complete, "*Year 1*" is the current year, "*Year 2*" and "*Year 3*" are forecasted years.

These results are based on inputs from the user (see how to forecast data in the model in Use Case 1)

At this stage of the COS study, the user has reviewed the inputs and the COS results. The next section will discuss how the user can use the COS model to design the tariffs.

2.4 USE CASE 3: DESIGN AND CALCULATE END-USER RATES

The following Use Case will discuss the design and calculation of end-user tariffs. After inputting all relevant assumptions (see Use Case 1) and reviewing the COS results and data quality diagnostics (Use Case 2), the user can start designing the tariffs. The relevant sheet to undertake the analysis is *"**Rate Design Dashboard**"*.

In the "***Rate Design Dashboard***" sheet, the first section compares the BAU (Business-as-usual), COS and new rates results. The user should use this section as a dashboard when designing the tariffs. This section of the sheet only provides high-level results with key indicators. The following figure highlights how to interpret each indicator.

The BAU refers to the current revenues with existing rates

CTS refers to the cost to serve results (i.e. the total cost to serve)

New rates refer to the new revenue based on the rates defined by the user later in this sheet

The "*average increase in rates*" is based on the new rates designed by the user later in this sheet

In this example, the user decided to increase the tariff by 3,0% on average for all customer categories

Results BEFORE phasing

	BAU	CTS (net of subsidies)	New rates (Dashboard selection)
Total revenue forecast (with new rates)	176 639 781	186 865 911	**181 938 975**
Average rate (R/kWh)	2,680513718	2,84	**2,76**
		Delta =	- 4 926 936
Average increase in rates	**3,0%**		
Average increase in rates to reach overall cost-reflectivity	5,8%		
Share of total cost recovered with the new rates	**97,4%**		
Share of total costs recovered (existing rates)	**94,5%**		

The "*average increase in rates to reach overall cost-reflectivity*" refers to the necessary increase in tariffs for the municipality to recover its costs based on the COS results

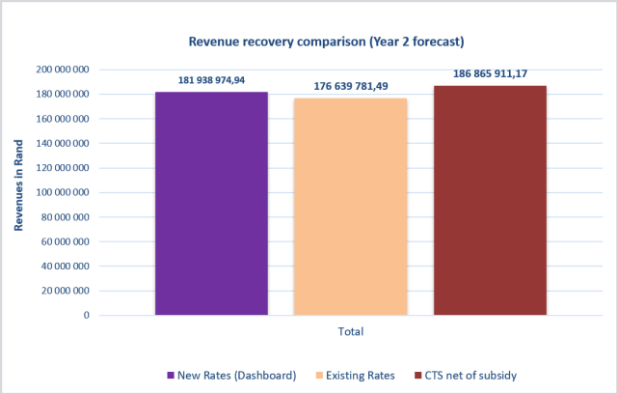
In this example, the user must increase the average tariff by 5,8% to recover all its cost for Year 2

The "*share of total cost recovered with the new rates*" shows if new rates are recovering all the municipalities costs

In this example, 97,4% of costs are recovered as the revenue with new rates (182m) is less than the total costs from the COS study (187m)

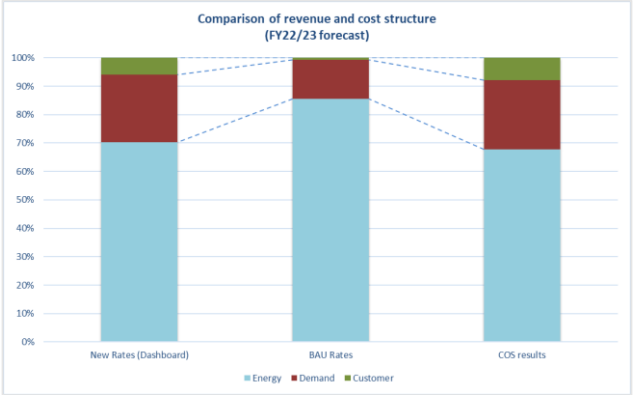
The "*share of total cost recovered (existing rates)*" shows if the existing rates are recovering all the municipalities costs

In this example, only 94,5% of costs are recovered with the existing rates, which means that the revenues from the current rates (177m) are not recovering the total municipality costs (187m)



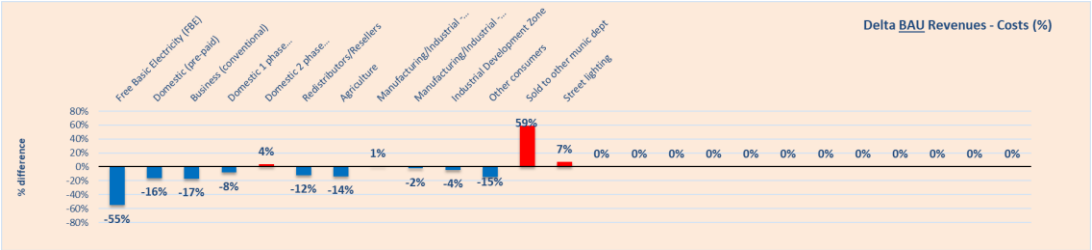
This figure compares new revenues with new rates, current revenues with existing rates (Business-as-usual) and the revenue required to recover all the costs following the COS analysis. In this example, the current tariffs are not recovering all costs

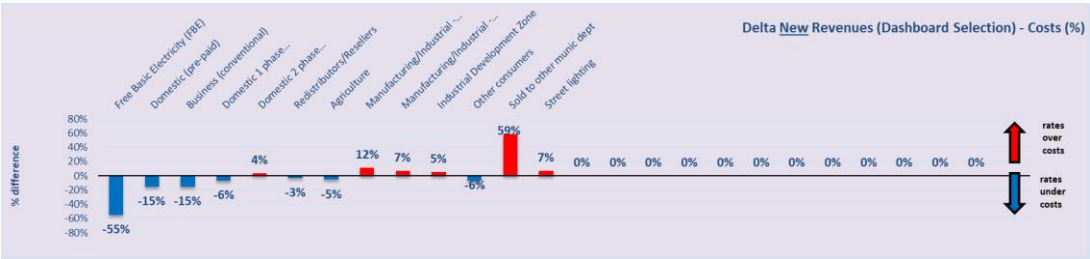
In this example, the new rates (left column) are recovering all costs (right column) compared to the BAU scenario (middle column). The new rates are designed later in this sheet.



This figure compares the new revenue cost structure, current revenue (BAU) cost structure and the cost structure computed by the COS study.

In this example, the new rates (left column) are more cost-reflective than the BAU scenario (middle column) compared to the COS results (left column). The new rates are designed later in this sheet.





These figures show the percentage of cross-subsidy between each customer category for the Business-As-Usual scenario and the new revenues with new rates scenario.

In this example, the overall increase in tariffs is due to an increase in tariffs for all customer categories between the "Redistributors" to the "Other consumers" as all categories are increasing their cross-subsidy. This is defined later by the user.

The following sections are tables to design the tariffs. The "***Average rate inputs***" section is for the user to input the average change in rates for each customer category.

Average rate inputs

Customer Categories	Type of rate setting input selected	Average increase in rates (%)	Total average rate (cR/kWh)	Increase required to reach full cost-reflectivity (%)	New total average rate (cR/kWh)	Resulting tariff increase (%)
Free Basic Electricity (FBE)	Average increase in rates (%)	0.0%		122.4%	202.9	0.0%
Domestic (pre-paid)	Average increase in rates (%)	1.0%		19.4%	235.8	1.0%
Business (conventional)	Average increase in rates (%)	2.0%		20.5%	285.9	2.0%

The user must select how to input the increase in rates. Either as a percentage increase or as a total average rate in cR/kWh

The selection should be based on the data available

The user should input the increase depending on the selected methodology

The level of increase should be based on the COS results to ensure the costs are recovered while considering the implications of increasing each customer category's tariffs. The user should use the figures highlighted above to see the impact of each increase

This column indicates the required increase to reach full cost-reflectivity without cross-subsidy for each customer category

This is an indicator only based on the COS results to support the design of tariffs.

Based on the increase inputted by the user, the two columns highlight the change in tariffs for each customer category in percentage or as cR/kWh

These are indicators only to support the design of tariffs.

In the "***Rate structure inputs***" section the user defines the rate structure between a variable charge in c/kWh based on the amount of energy consumed, a demand charge in R/kVA/month based on the maximum demand of the user, and a fixed charge in R/POD/month.

Rate structure inputs

		1			2			3
Customer Categories	Type of kVA charge	Share of revenues recovered from variable charges (c/kWh)	BAU	CTS	Share of revenues recovered from demand charges (R/kVA/month)	BAU	CTS	Share of revenues recovered from fixed charges (R/POD/month)
Free Basic Electricity (FBE)		60%	100%	41%	0.0%	0%	31%	40%
Domestic (pre-paid)	per KVA of MD metered	55%	100%	55%	5.0%	0%	26%	40%
Business (conventional)		46%	100%	46%	0.0%	0%	18%	54%

If a share of revenues recovered from demand charges is selected, the user can decide which type of kVA can be charged (per kVA of Maximum Demand metered or subscribed)

The selection should be based on the current rate structure. The user may also decide to introduce changes to rate structures here.

The user must select the share of revenues recovered from each type of charge for each customer category

The selection should be based on the current rate structure. The user may also decide to introduce changes to rate structures here.

The two columns allow the user to see the current rate structure (BAU) and "ideal" rate structure based on the COS analysis

In the "***Tariff TOU design inputs***" the user can change the rate structure by including TOU and seasonal energy rate for each customer category and include a seasonal demand rate.

Tariff TOU design inputs

Customer Categories	TOU energy rates?	Seasonal energy rates?	Seasonal demand rates?	Peak pricing signal	BAU	CTS	Standard pricing signal
Free Basic Electricity (FBE)	TRUE	TRUE	TRUE	150%	100%	-694%	125%
Domestic (pre-paid)	FALSE	TRUE	FALSE	100%	100%	-694%	100%
Business (conventional)	FALSE	FALSE	TRUE	100%	100%	-694%	100%

The user must select for each customer category if energy rates should have TOU and seasonal pricing.

The selection will directly impact the rate structure in the "*Tarif Schedule (Year 2)*" sheet.

If TOU pricing is selected, the user can include pricing signals by increasing tariffs under a TOU period.

The selection will directly impact the rate amount in the "*Tarif Schedule (Year 2)*" sheet. In this example, the peak time period will have higher tariffs than the standard time period for the FBE customer category.

In the "***Wheeling / Retail: split of cross-subsidy (>0 or <0) between business area***" the user can include a cross-subsidy between the wires and retail and business areas by assigning a weighting factor.

Wheeling / Retail: split of cross-subsidy (>0 or <0) between business area

Customer Categories	Wires weighting factor	Retail weighting factor	Amount of cross-subsidy to split (Rand)
Free Basic Electricity (FBE)	50%	50%	- 138,089,575.2
Domestic (pre-paid)	50%	50%	- 100,610,493.3
Business (conventional)	50%	50%	- 9,796,308.3

The weighting factor should be included here

The selection will directly impact the rate structure in the "*Tarif Schedule (Year 2)*" sheet

2.5 USE CASE 4: RATE IMPACT ANALYSIS

The following Use Case will highlight how to see the updated tariff schedule for each customer category and observe if any change exposes any potentially unacceptable distortions. The relevant sheets for this Use Case are "***Tariff Schedule (Year 2)***" and "***Rate Impact Results (Year 2)***".

In the "***Tariff Schedule (Year 2)***" sheet, the user can see the detailed tariff structure for each customer category.

			Free Basic Electricity (FBE)		
Standing Charge	Rand/month		0.0		
Demand charge	Rand/kVA/month		High season	Low season	
			0.0	0.0	
			High season	Low season	Any season
Variable charge	cR/kWh	Offpeak	259.5	259.5	259.5
		Standard	413.6	413.6	413.6
		Peak	496.3	496.3	496.3
		Any TOU	336.9	328.6	202.9

In this example the FBE customer category has no demand and standing charge selected. This can be changed in the ratemaking input section in the "*Rate Design Dashboard (Year 2)*" sheet

The results are based on the design of tariffs in Use Case 3.

In this example the FBE customer category has a variable charge with a higher rate for the off-peak period with no demand and standing charge selected

The results are based on the design of tariffs in Use Case 3.

	RATE COMPARISON							
	New rates for Year 2 (dashboard) (Wires+Retail)				Existing rates in Year 1 (Wires + Retail)			
Customer Categories	Standing charge	Average demand rate	Average energy rate	Total average rate	Standing charge	Average demand rate	Average energy rate	Total average rate
	Rand/month	Rand/kVA/month	cR/kWh	cR/kWh	Rand/month	Rand/kVA/month	cR/kWh	cR/kWh
Free Basic Electricity (FBE)	-	-	203	203	-	-	203	203
Domestic (pre-paid)	-	-	235	235	-	-	234	234
Business (conventional)	-	-	283	283	-	-	280	280
Domestic 1 phase (conventional)	-	-	234	234	-	-	232	232
Domestic 2 phase (conventional)	54	-	232	237	54	-	232	237
Redistributors/Resellers	278	-	257	276	265	-	245	263
Agriculture	1,250	366	102	195	1,192	349	97	186
Manufacturing/Industrial - large	1,125	164	180	213	1,073	156	172	204
Manufacturing/Industrial - small	1,080	164	177	219	1,030	156	169	209
Industrial Development Zone	2,108	142	166	193	2,010	136	158	184
Other consumers	1,941	142	97	281	1,851	136	92	268
Sold to other munic dept	452	-	341	341	452	-	341	341
Street lighting	265	-	245	245	265	-	245	245

This table compares the existing rate for each customer category to the new rates designed in the "Rate Design Dashboard (Year 2)"

3. APPENDIX

3.1 USE CASE 5: CONDUCTING AN ACCELERATED COS STUDY WITH THE SIMPLIFIED VERSION

In this use case, the model is simplified for users who have access to limited data. This does not mean that the model captures less information required to conduct a COS study, rather some inputs are automatically pre-populated which makes it easier for the user to conduct the COS study. All inputs that are pre-populated are in orange and all inputs that need to be filled in by the user are in yellow. The pre-populated inputs are largely based on data typically included in the d-forms. Under each step of this use case, a specific worksheet is discussed, including which inputs are pre-populated, input required from the user and where to find the data. The results of Use Case 2 will be a COS analysis, specific to the municipality based on the data provided.

3.1.1 Data requirements and implications of using simplified mode

The simplified version of the tool is intended to reduce the level of effort and data granularity required to undertake a COS study. It provides a practical option for municipalities that may not have access to all the detailed technical, financial and commercial data required for expert mode, or that may not have the internal capacity to undertake a fully detailed COS study. The trade-off is that the simplified version relies on a greater number of simplifying assumptions and pre-populated inputs, which may reduce the precision of the results when compared with a study based on fully municipality-specific data.

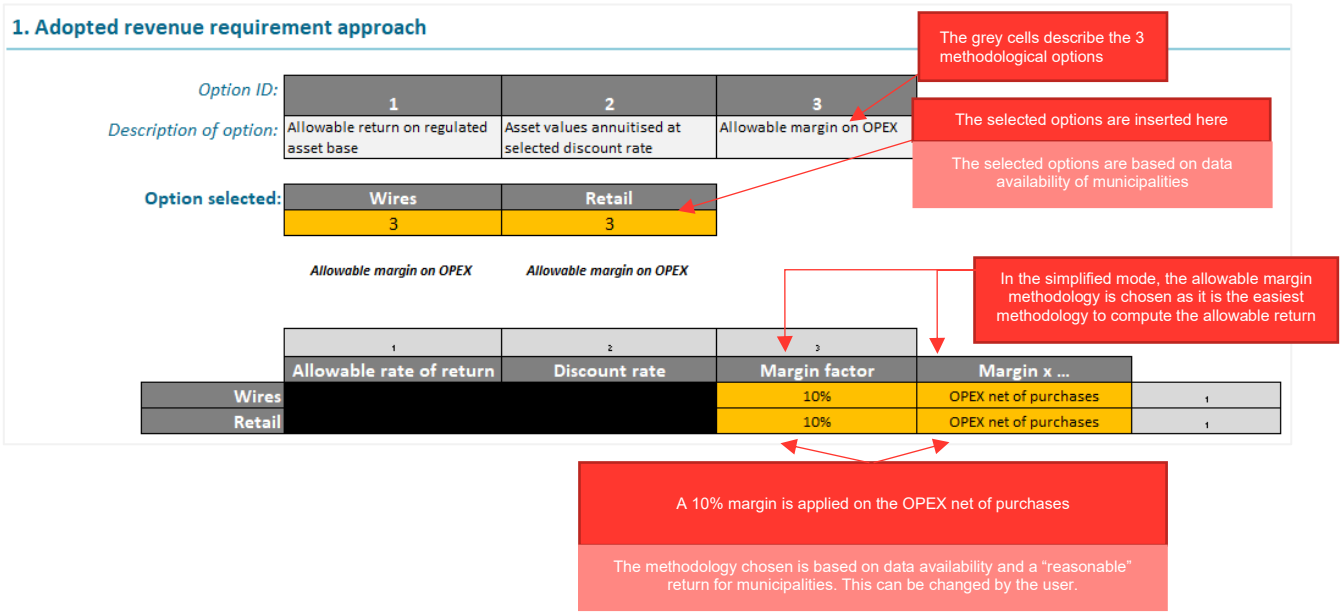
This does not mean that the simplified version should be treated as a generic or fixed calculation. The assumptions and pre-populated data used in this mode are expanded on in the sections below and should be reviewed by the user before the results are relied upon. Where the default assumptions do not reflect the municipality's circumstances, they should be updated to the best of the user's knowledge. This review is important because the quality of the COS outputs remains dependent on the reasonableness of the inputs and assumptions used in the model.

Where more detailed information is available, the user should replace the pre-populated data with municipality-specific data. This will improve the accuracy of the calculations and produce COS results that are more closely aligned with the municipality's actual cost to serve each customer category. The simplified version should therefore be understood as a flexible starting point: it reduces the initial data burden and makes the model more accessible, while still allowing the user to improve the robustness of the results as better information becomes available.

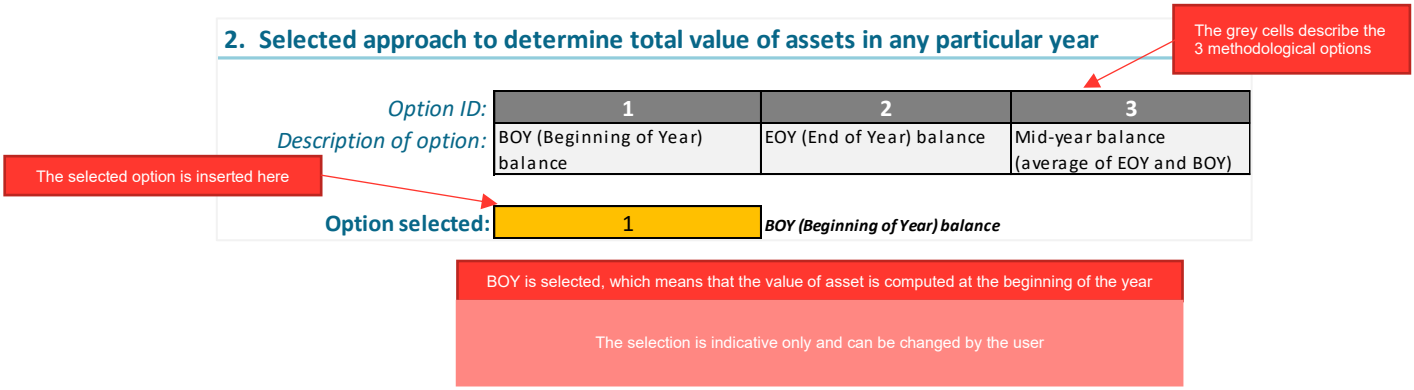
3.1.2 Input on the “Methodology Inputs” sheet for the COS analysis

The simplified mode pre-populates several inputs in orange**.** What is required from the user in this step is to review the pre-populated inputs and make changes if necessary. The figures below describe each input.

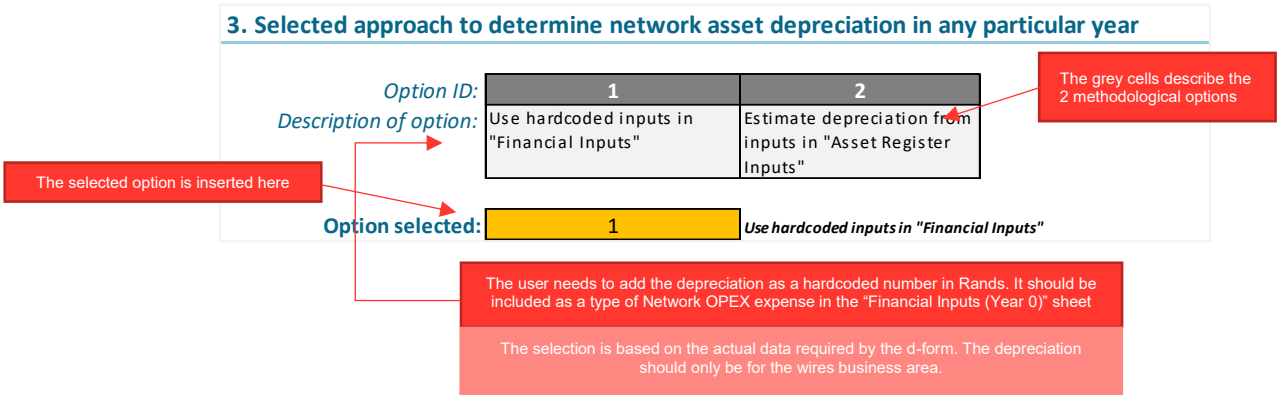
The “***Adopted revenue requirement approach***” defines the methodology used to compute the allowed return included in the revenue requirement. In the simplified mode, the allowable margin on OPEX methodology is selected as it is the easiest option based on the data availability.



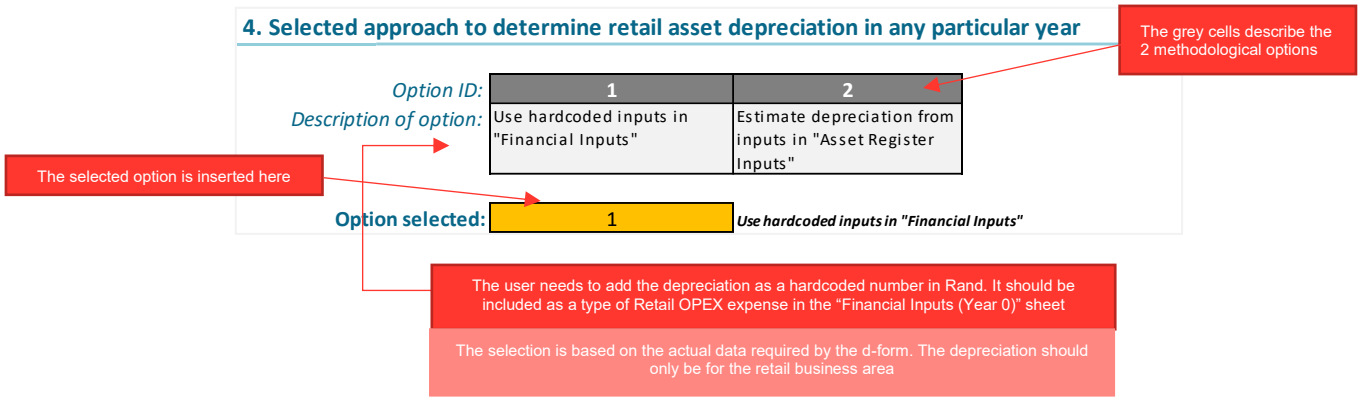
The "***Selected approach to determine total value of assets in any particular year***" defines when the value of assets should be taken into account. The pre-populated approach is at the Beginning of the Year, which is indicative and can be changed by the user.



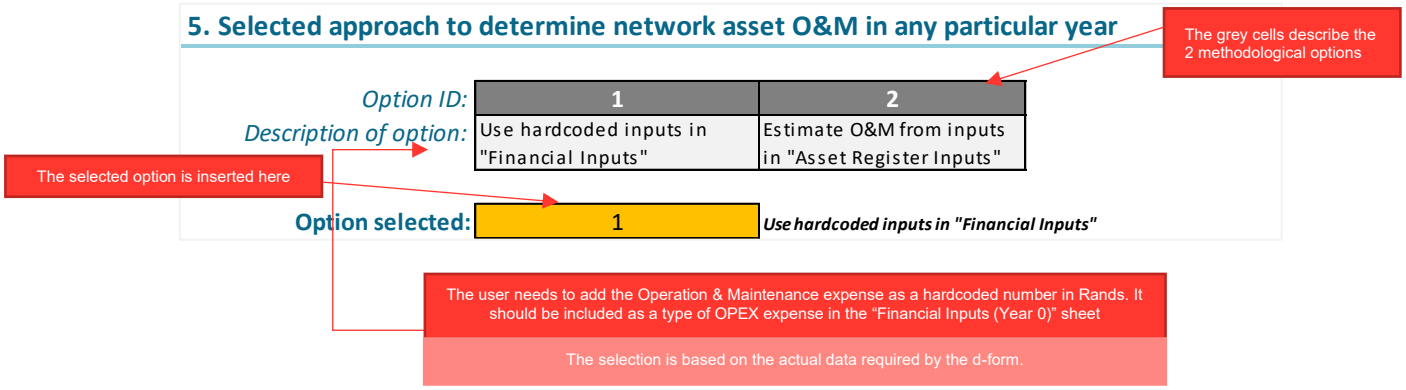
The "***Selected approach to determine network asset depreciation in any particular year***" defines the methodology to assess the depreciation of network assets. The pre-populated approach is for the user to input depreciation in Rands.



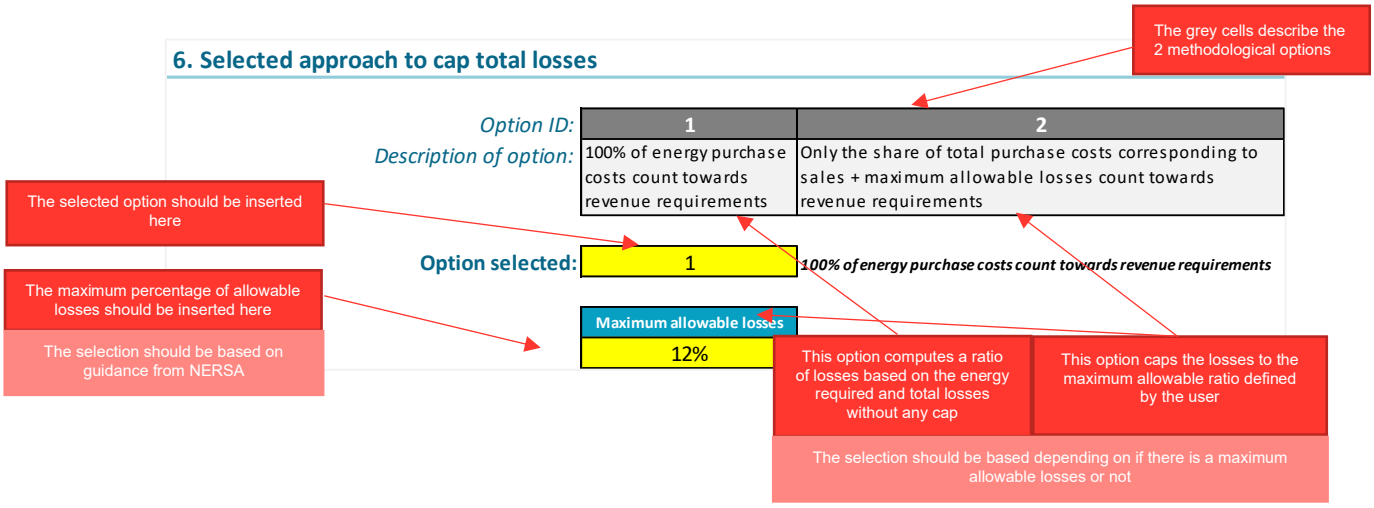
The "***Selected approach to determine retail asset depreciation in any particular year***" defines the methodology to assess the depreciation of retail assets. The pre-populated approach is for the user to input depreciation in Rands.



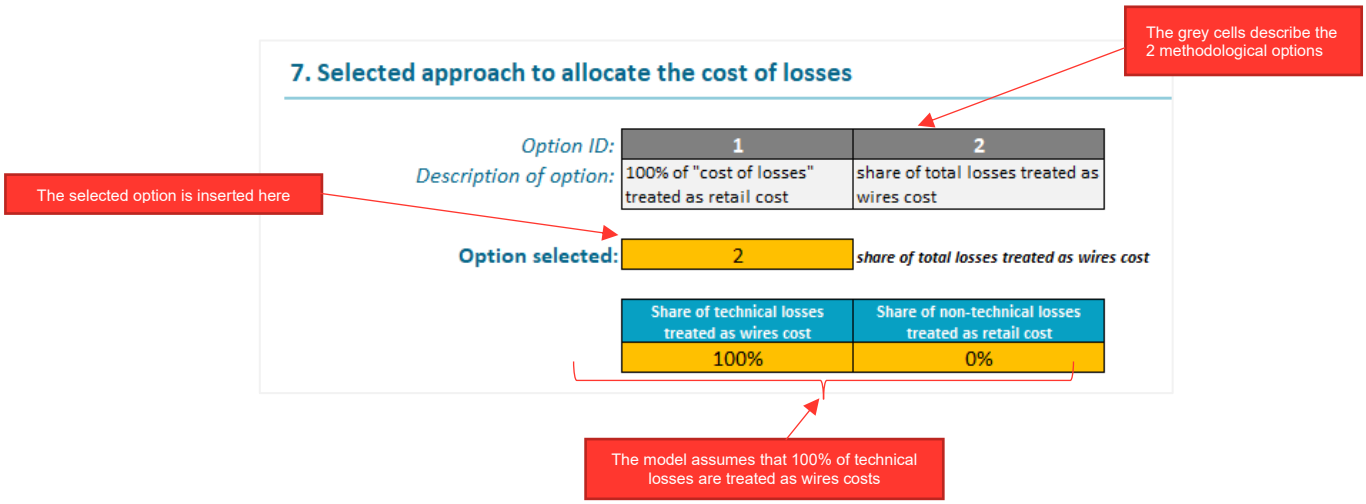
The "***Selected approach to determine network asset O&M in any particular year***" defines the methodology to assess the Operations and Maintenance (O&M) costs. The pre-populated approach is for the user to input the Operation & Maintenance costs in Rands.



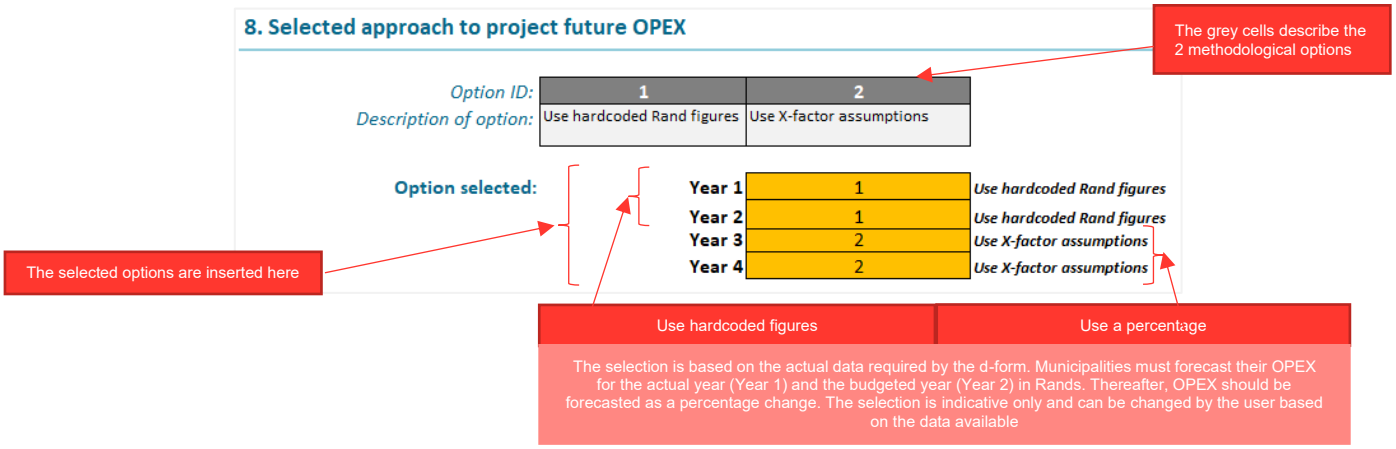
The **"*Selected approach to cap total losses*"** allows the user to decide the level of allowable losses a utility can include in its revenue requirement.



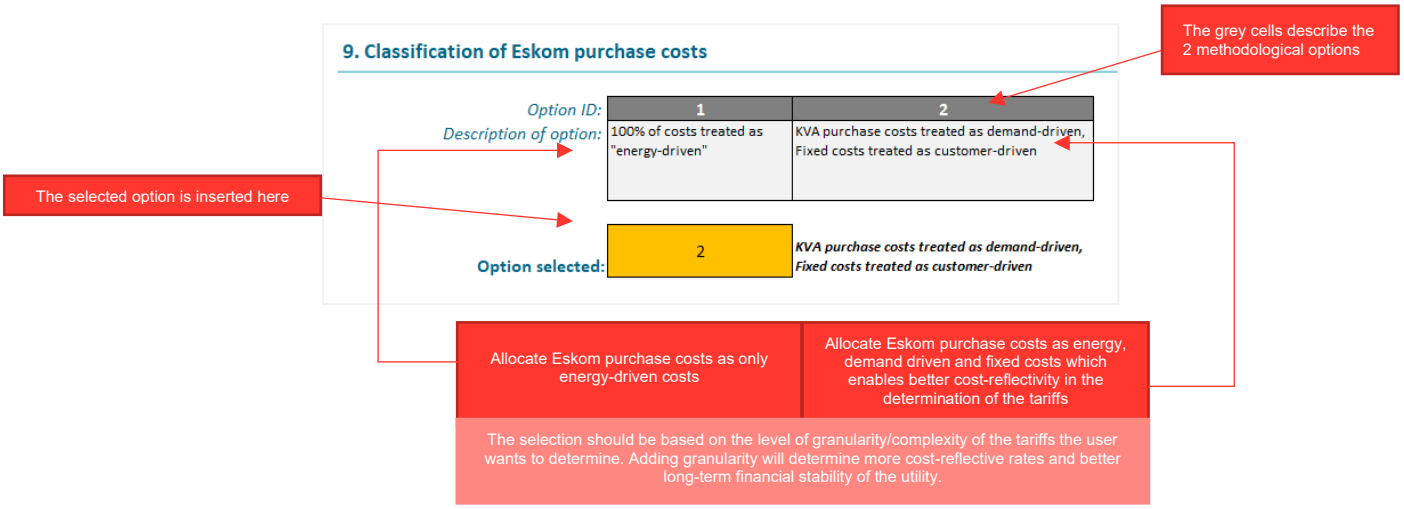
The "***Selected approach to cap total losses***" allows the user to decide whether to allocate the cost of losses as a retail cost or as a share between the wires and retail business areas.



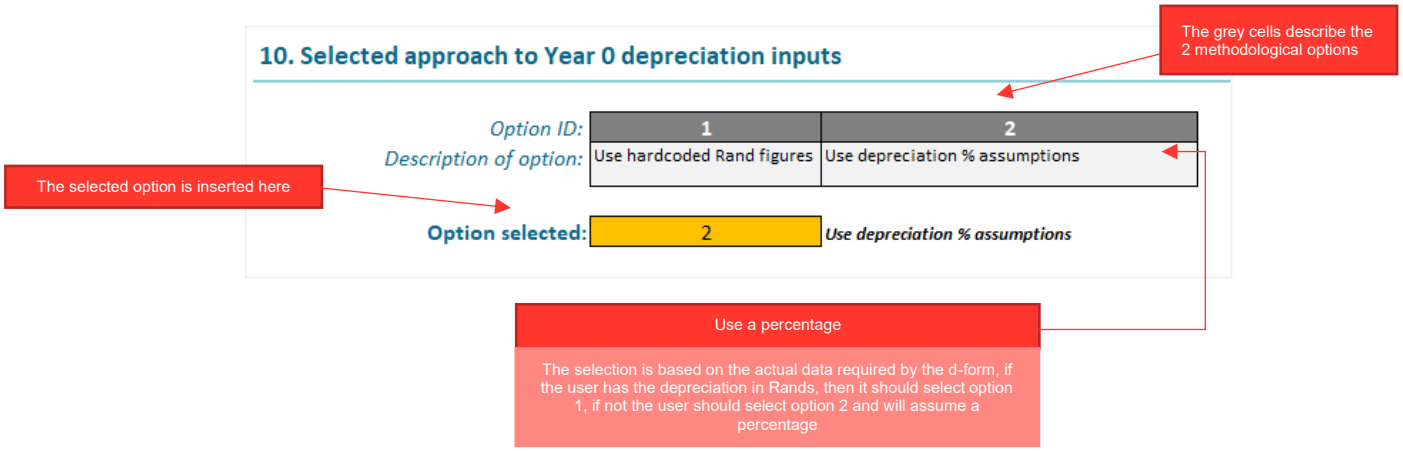
The "***Selected approach to project future OPEX***" is defining how to forecast future OPEX, either as a percentage increase/decrease or hardcoded figures for each year. The pre-populated approach is for the user to input the actual and budgeted OPEX in Rands and to forecast as a percentage increase/decrease in Years 3 and 4.



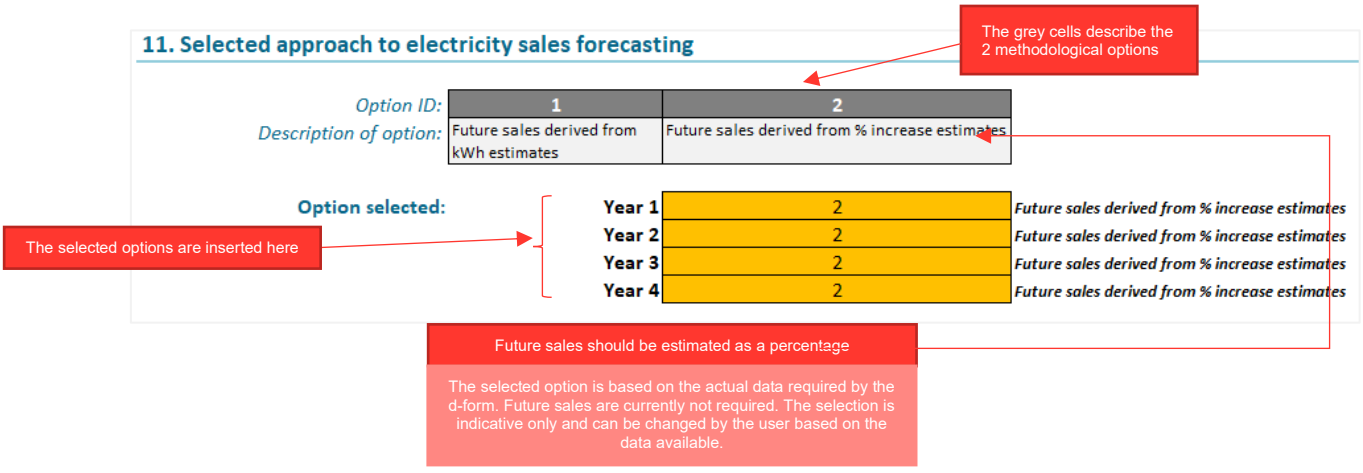
The "***Classification of Eskom purchase costs***" determines whether Eskom's purchase costs should be only allocated as energy-driven costs or also demand and customer-driven costs. Energy-driven costs vary with energy consumption, Demand-driven costs vary with the system peak demand, and Fixed costs vary by the type of customer served



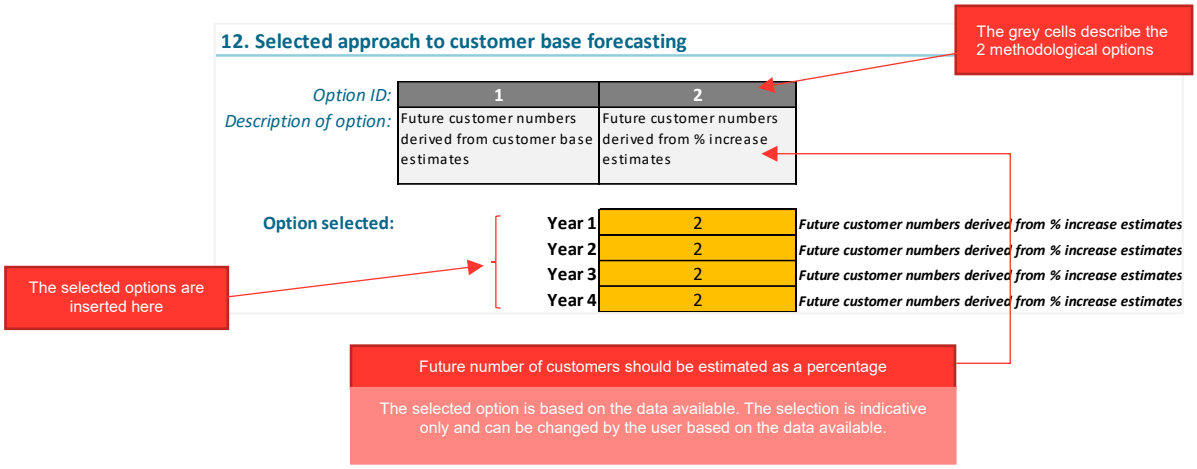
The "***Selected approach to Year 0 depreciation inputs***" defines whether the depreciation for Year 0 should be input in Rands or expressed as a percentage.



The "***Selected approach to electricity sales forecasting***" defines how to forecast future sales, either as a hardcoded figure in kWh or a percentage increase/decrease for each year. The pre-populated approach is for the user to input a percentage increase for all years.



The "***Selected approach to customer base forecasting***" defines how to forecast the number of customers, either as a hardcoded figure or a percentage increase/decrease for each year.

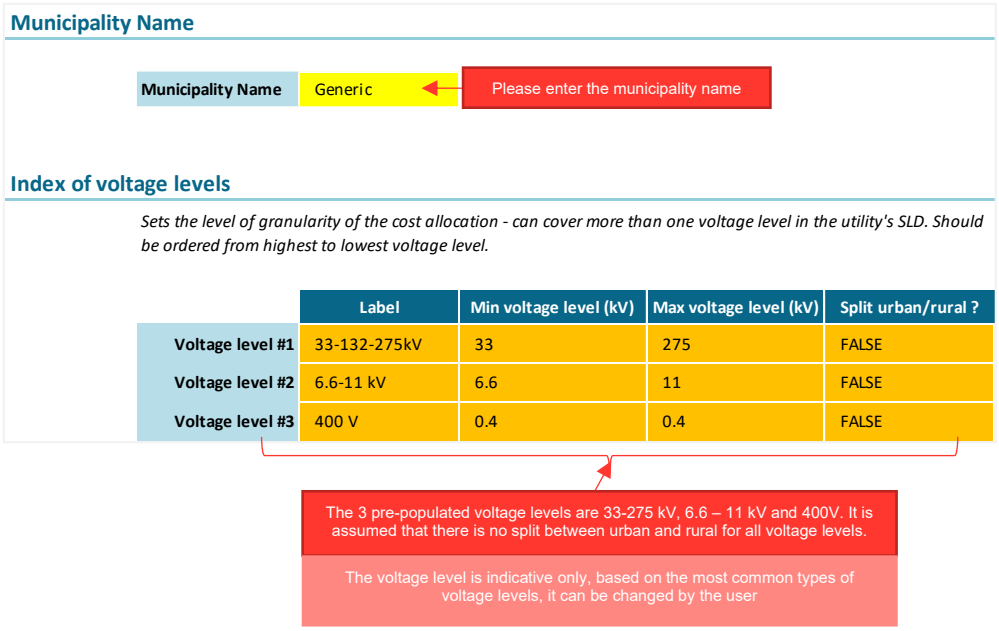


At this stage of the COS analysis, the user has reviewed all the methodology options to determine the tariffs. In the next sections, the user will need to review and provide assumptions with historical and forecasted values to compute the tariffs.

3.1.3 Capturing data into the model's "Index Tables" worksheet

What is required from the user in this step is to first, review the pre-populated inputs, and second, populate additional inputs in the "Index Tables" sheet which the model will refer to throughout the COS analysis. It is important that this sheet is completed before completing any sheets that follow. All cells in orange are pre-populated inputs and all cells in yellow need to be filled in by the user. The following figures discuss the main tables in the "Index Tables" worksheet and the required actions by the user.

The "***Municipality Name***" needs to be filled in to identify the utility. The "***Index of voltage levels***" defines the voltage levels of the assets to compute the losses associated with each voltage level. The pre-populated voltage levels are based on the most common types of assets.



The "***Index of customer categories***" provides key information for each customer category to determine different tariffs for each customer category.

Index of customer categories

Sets the level of granularity of the cost allocation - can cover more than one voltage level in the utility's SLD

	Label	RND asset group including intake point	Monthly data available?	TOU data available and TOU tariffs in place?	Use manual % inputs for TOU allocation?	Services provided include BOTH wheeling & retail?	Wheeling boolean	Category Group	New category in Year > 0?	Category most similar to new one
Customer category #1	Domestic (pre-paid)	400 V / Mixed	FALSE	FALSE		TRUE	1	Domestic customers	FALSE	Domestic (pre-paid)
Customer category #2	Domestic (conventional)	400 V / Mixed	FALSE	FALSE		TRUE	1	Domestic customers	FALSE	Domestic (conventional)
Customer category #3	Agriculture	33-132-275kV / Mixed	FALSE	FALSE		TRUE	1	Industrial customers	FALSE	Domestic (pre-paid)

The name of customer categories is pre-populated along with the relevant voltage level. The monthly data is not available for all customer categories

The selection is based on the actual data required by the d-form. The labels of customer categories and annual data requirements are aligned with the d-form. The relevant voltage levels have been allocated based on the type of customer. The selection can be changed by the user.

Time Of Use data is not available in the simplified mode

The selection is based on the actual data required by the d-form, which does not include TOU data. The selection can be changed by the user.

The user can manually input the Time Of Use allocation. This is optional

All customer categories benefit both from wheeling & retail services

The selection is based on the actual data required by the d-form, which does not differentiate between wheeling and retail business areas. The selection can be changed by the user

Each customer category is allocated to a macro-category for analysis purposes

The selection is based on the labels of each customer category required in the d-form

The "***Index of functions***" identifies the OPEX category costs and allocates them to their business areas and cost classes (energy, demand and fixed-driven costs).

Define the labels of the business areas if applicable.

Index of functions

Business areas:	Wires	Retail

	Label	Function included in Wires OPEX list	Function included in Retail OPEX list	Split by class: Energy	Demand	Customer	Function included in margin baseline?	Function related to purchasing costs?
Function #1	*Eskom Energy Purchase - excl. losses*	FALSE	FALSE				FALSE	TRUE
Function #2	*Eskom Energy Purchase - cost of losses*	FALSE	FALSE				FALSE	TRUE
Function #3	*Other Energy Purchase*	FALSE	FALSE	100%	0%	0%	FALSE	TRUE
Function #4	*CAPEX and return*	TRUE	FALSE	0%	100%	0%	FALSE	FALSE
Function #5	*Depreciation*	TRUE	TRUE	0%	100%	0%	TRUE	FALSE
Function #6	*Network repairs & maintenance*	TRUE	FALSE	0%	100%	0%	TRUE	FALSE
Function #7	Salaries	TRUE	TRUE	0%	0%	100%	TRUE	
Function #8	Financial costs	FALSE	TRUE	0%	0%	100%	TRUE	
Function #9	Other 1	TRUE	TRUE	0%	0%	100%	TRUE	

The user is to include any OPEX category that exists in their financial statement. Further, each item should be split by business area i.e wires or retail

This information should be included in the financial statements of the utility.

The OPEX items are to be classified as energy, demand, fixed or a combination of these on a % basis

The percentage should be assumed based on the costs included in the function. Energy class are costs that vary with the consumption of energy, Demand class are costs that vary with the system peak demand, Fixed class are costs that vary by the type of customer served.

The user should choose whether the line item should be included in the margin baseline

The user should choose whether the line item relates to purchasing costs.

Function designating asset depreciation:	Depreciation
Function designating network asset O&M:	Network repairs & maintenance
Function designating CAPEX:	CAPEX and return
Function to allocate "purchase margin" when applicable	Network repairs & maintenance

These are the pre-defined functions related to depreciation, network asset O&M, CAPEX and purchase margin (when applicable). This is to inform the model on the category cost that should be allocated for these 4 key functions. The purchase margin is the additional purchases that should be included in the calculation of the allowable margin on OPEX net of purchases

The "***Index of Eskom intake points***" is for the user to label the Point of Delivery (POD) when computing the Eskom purchase volumes.

Index of Eskom intake points

	Name	Monthly data available?
POD #1		FALSE
POD #2		FALSE
POD #3		FALSE
POD #4		FALSE
POD #5		FALSE

The user must add the required number and names of Points Of Delivery (PODs) based on the system. The user must also indicate whether monthly data is available for each POD.

This information should be in the billing data from Eskom.

3.1.4 Capturing non-Eskom power purchase inputs

This step requires the user to capture any other sources of electricity that may exist outside of the electricity purchased from Eskom. As mentioned in section 1.3.3 Year 0 refers to the historical data (i.e., when the last complete set of data is available). The following figure highlights the inputs required in this step.

Non-Eskom Purchase Inputs

Non-Eskom Sources of Electricity Purchases	Volume in Year 0 (kWh)	Volume in Year 1 (kWh)	Volume in Year 2 (kWh)	Volume in Year 3 (kWh)	Volume in Year 4 (kWh)	Contribution to meeting coincident peak in Year 0 (kVA)	Coincident plant factor	TOU split % Offpeak	Standard	Peak
DG Exports	817,242	976,415	1,063,725	1,229,780	1,829,780	400	23%	0%	100%	0%
Independent Power Producers Conventional						-	0%			
Independent Power Producers Renewable Energy						-	0%			
Self Generation	12,045,687	12,065,874	12,106,578	12,089,125	12,084,321	12,098,456	0%			
Other						-	0%			
Total	12,862,929	13,042,289	13,170,303	13,318,905	13,914,101	12,098,856				

The user must include the volume in kWh in Year 0 to Year 4 for each non-Eskom source of generation

This information should be included in the financial statements and/or applicable invoices to the utility.

The user should assume a value in kVA of contribution to peak demand for each source of electricity purchases

This information depends on the utility's total generation profile data and the generators' profile data.

The user should enter the TOU split for distributed generation exports.

This information is used to identify during which TOU period the energy is generated.

3.1.5 Capturing Financial Inputs (OPEX)

This step involves the user capturing the financial inputs relating to OPEX, non-electricity revenues as well as non-Eskom purchase inputs. The following figures highlight the required actions within this sheet.

OPEX inputs (non purchase)

	Year 0 estimate	Electricity Supply Share (%)	Wires Share (%)	Retail Share (%)	Function (Wires)	Function (Retail)
Depreciation		100%	57%	43%	Depreciation	Depreciation
Network repairs & maintenance		100%	53%	47%	Repairs, Maintenance	Repairs, Maintenance
Salaries		100%	53%	47%	Salaries	Salaries
Financial costs		100%	53%	47%	Financial costs	Financial costs

The user is to define non purchase OPEX items along with their values in Rands for Year 0.

The user is to allocate the relevant OPEX item to each business area,

This assumption should be based on the source of the OPEX. A ratio could be determined based on the OPEX of each business area.

The user is to choose the relevant function from the dropdown for each OPEX item

The dropdown is based on the functions defined in the "Index Tables" sheet.

Non-electricity supply revenues *(will be netted out of OPEX)*

	Year 0 estimate	Electricity Supply Share (%)	Wires Share (%)	Retail Share (%)	Function (Wires)	Function (Retail)
Other revenues						
Reconnection fees	R -	100%	10%	90%		Other
New connections	R -	100%	100%	0%	CAPEX and return	

The user is to define other revenue items along with the amount in Year 0 in Rands

This should be included in the financial statements.

The user should allocate the revenue to each business area

This assumption should be based on the source of the revenue. A ratio could be determined based on the revenues of each business area.

The model pre-populates the allocation of each revenue source to the wires and retail functions.

Non-Eskom Purchase Inputs

Sources of Electricity Purchases	Type of purchase cost input	Purchase costs in Year 0	Average rate in Year 0 in cR/kWh	Annual escalation
DG Exports	Average rate in Year 0 in cR/kWh	R -	-	
Independent Power Producers Conventional	Purchase costs in Year 0	R -	-	
Independent Power Producers Renewable Energy	Purchase costs in Year 0	R -	-	
Self Generation	Purchase costs in Year 0	R -	-	
Other	Purchase costs in Year 0	R -	-	
Total				

The user must define Non-Eskom purchase cost in Rands or the average rate in cR/kWh

This should be included in financial statements

The user must define an annual escalation factor to these purchases as a percentage

This should be included in financial statements

3.1.6 Capturing Eskom Power Purchase Volumes

This step involves the user capturing the Eskom Purchase volumes for the various PODs. Further, the power factor for each POD is also to be defined. If monthly data is not available for particular PODs, annual purchased volumes can be included and manual TOU and seasonal ratios can be included.

Energy (kWh) purchase inputs

			Total monthly purchases (kWh)											
	POD Name	TOU period	July	August	September	October	November	December	January	February	March	April	May	June
1	POD 1													
	POD 1	OffPeak	1,817,242	2,076,415	1,863,725	1,929,780	1,908,066	2,007,897	2,038,248	1,747,023	1,871,352	2,008,535	2,043,265	1,920,032
	POD 1	Standard	1,994,374	1,933,786	1,840,103	1,882,596	1,808,798	1,775,574	1,755,654	1,721,596	1,896,564	1,709,300	1,904,532	1,938,762
	POD 1	Peak	874,581	793,938	802,423	764,777	755,425	727,525	675,324	719,714	770,375	706,686	785,458	862,307

The user must input the monthly purchases from Eskom in kWh for each Point Of Delivery

This should be included in the invoices from Eskom for Year 0.

Demand (kVA) purchase inputs

			Total monthly purchases (kVA)											
	POD Name	MD/NMD	July	August	September	October	November	December	January	February	March	April	May	June
1	POD 1													
	POD 1	MD	11,926	10,796	11,963	10,882	9,989	9,602	10,228	11,377	9,762	10,428	10,417	13,046
	POD 1	NMD	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000

The user must input the monthly purchases from Eskom in kVA for each Point Of Delivery

This should be included in the invoices from Eskom for Year 0.

3.1.7 Capturing Commercial Inputs

The user is to capture energy sales inputs for the various customer categories over all months or per year depending on the methodology chosen in the “Index Tables” sheet. Further, the number of customers in each category is to be defined.

Energy (kWh) sales inputs

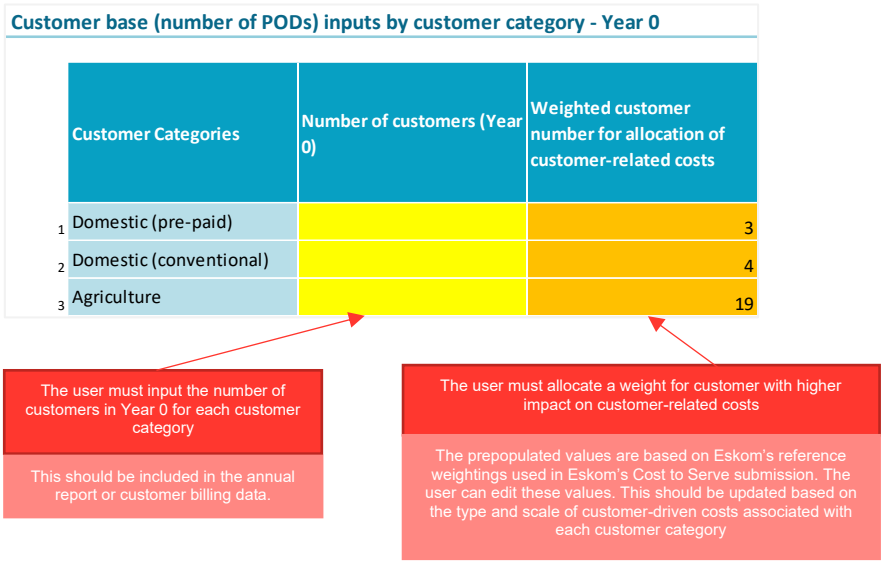
	Customer category	TOU period	TOTAL annual - manual	High Season	Low Season
1	Domestic (pre-paid)		FALSE		
	Domestic (pre-paid)	All		30%	70%
	Domestic (pre-paid)				
	Domestic (pre-paid)				
2	Domestic (conventional)		FALSE		
	Domestic (conventional)	All	-	30%	70%
	Domestic (conventional)				
	Domestic (conventional)				

Since the user did not select “monthly data available” it must input the annual energy sales in kWh. If monthly data is available or if TOU data is available, it should change the option in the “Index Tables” sheet (see index of customer categories)

The annual energy sales inputs should be in the annual report and TOU data should be in the customer billing data for each customer category.

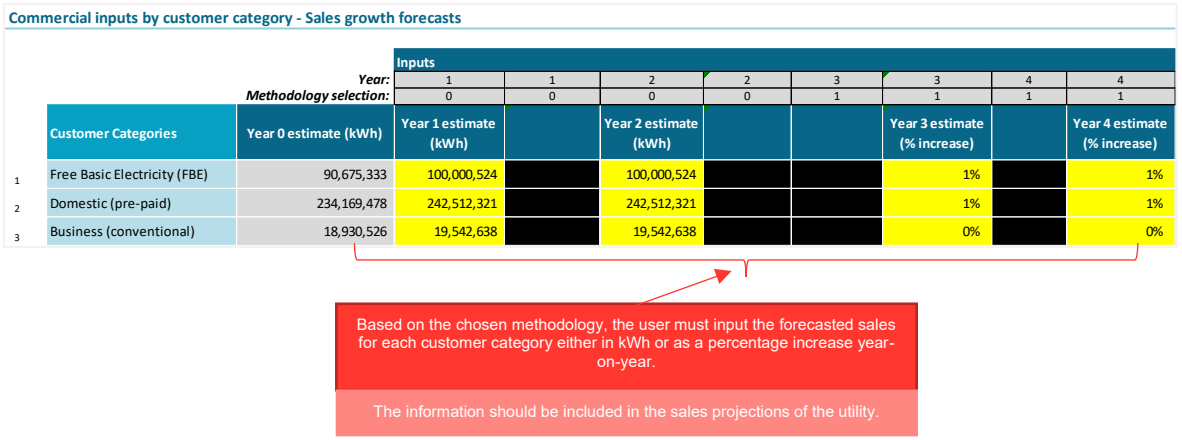
If monthly data is not available, the user can input a ratio to allocate the annual energy sales in kWh to the high and low seasons.

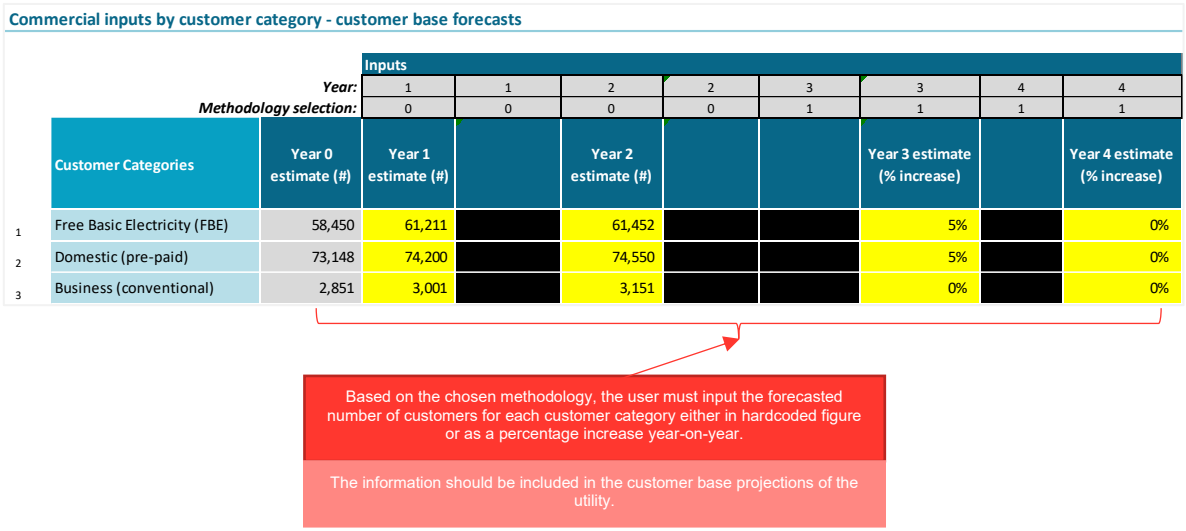
The pre-populated values are based on the high and low seasonal split of the Eskom tariffs. These values may be edited by the user.



3.1.8 Capturing Commercial Inputs (Years 1 - 4)

The user is to capture the expected increase in kWh sales to various customer categories along with potential growth in customer numbers. Further, the user is to input the year-on-year NTL % reduction, if applicable.





3.1.9 Capturing Financial Inputs (Years 1 – 4)

The user is to capture multi-year inputs relating to OPEX and other revenues. Further, inputs relating to future capital investment are also to be captured.

OPEX inputs (non purchase)

		Inputs							
Year:		1	1	2	2	3	3	4	4
Methodology selection:		1	0	1	0	1	0	0	1
	Year 0 estimate (Rand)	Year 1 estimate (Rand)		Year 2 estimate (Rand)		Year 3 estimate (Rand)			Year 4 estimate (nominal % increase)
Network OPEX	R 191,163,581	R 195,988,852		R 202,786,328	R -	R 232,158,411	R -	R -	R -
Salaries and allowances	R 91,826,876	R 94,665,413		R 97,409,950		R 118,810,989			0%
Contracted Services	R 1,404,477	R 1,432,567		R 1,489,870		R 671,448			0%
Materials and supplies	R 2,297,263	R 2,343,208		R 2,436,937		R 10,505,410			0%

Based on the chosen methodology, the user must input the forecasted amount of OPEX for each OPEX item either in hardcoded figures or as a percentage increase year-on-year.

The information should be included in the financial budgets of the utility.

Non-electricity supply revenues *(will be netted out of OPEX)*

	Year 0 estimate	Year 1 estimate (Rand)		Year 2 estimate (Rand)		Year 3 estimate (Rand)			Year 4 estimate (nominal % increase)
Other revenues									
Recon disconnect/Recon fees	R 1,927,256	R 1,965,801		R 2,044,433		R 7,744,304			0%
Service connections	R 1,472,703	R 1,456,257		R 1,514,507		R 19,594			0%
Meter reading fees	R 6,336	R 6,493		R 6,753		R 19,594			0%

Based on the chosen methodology, the user must input the forecasted amount of non-electricity supply revenues for each revenue category either in hardcoded figures or as a percentage increase year-on-year.

The information should be included in the financial budgets of the utility.

New core network capital investments

	Asset Group Label	Investments in year 1	Investments in year 2	Investments in year 3	Investments in year 4
1	33 - 88 - 132 kV / Urban	R 21,141,641	R 21,856,120	R 22,511,803	R 23,187,157
2	11 kV / Mixed	R 52,854,102	R 54,640,299	R 56,279,508	R 57,967,894
3	400 V / Mixed	R 17,924,435	R 18,530,188	R 19,086,094	R 19,658,677

The user must input the forecasted amount in Rands of network capital investment for each voltage level (labelled in the "Index Tables" sheet).

The information should be included in the business plan of the utility.

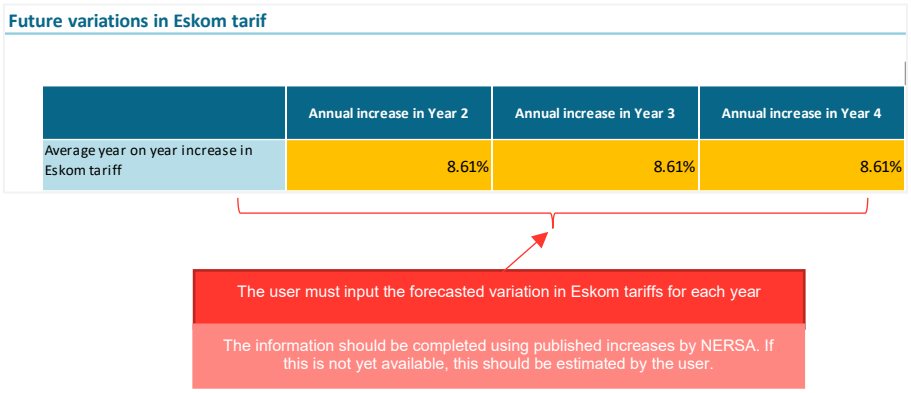
Other capital investments

Asset Group Names can only be edited in the "Asset Register Inputs" sheet

	Asset Group Label	Investments in year 1	Investments in year 2	Investments in year 3	Investments in year 4
1	Retail asset	R -	R -	R -	R -
2	XX	R -	R -	R -	R -

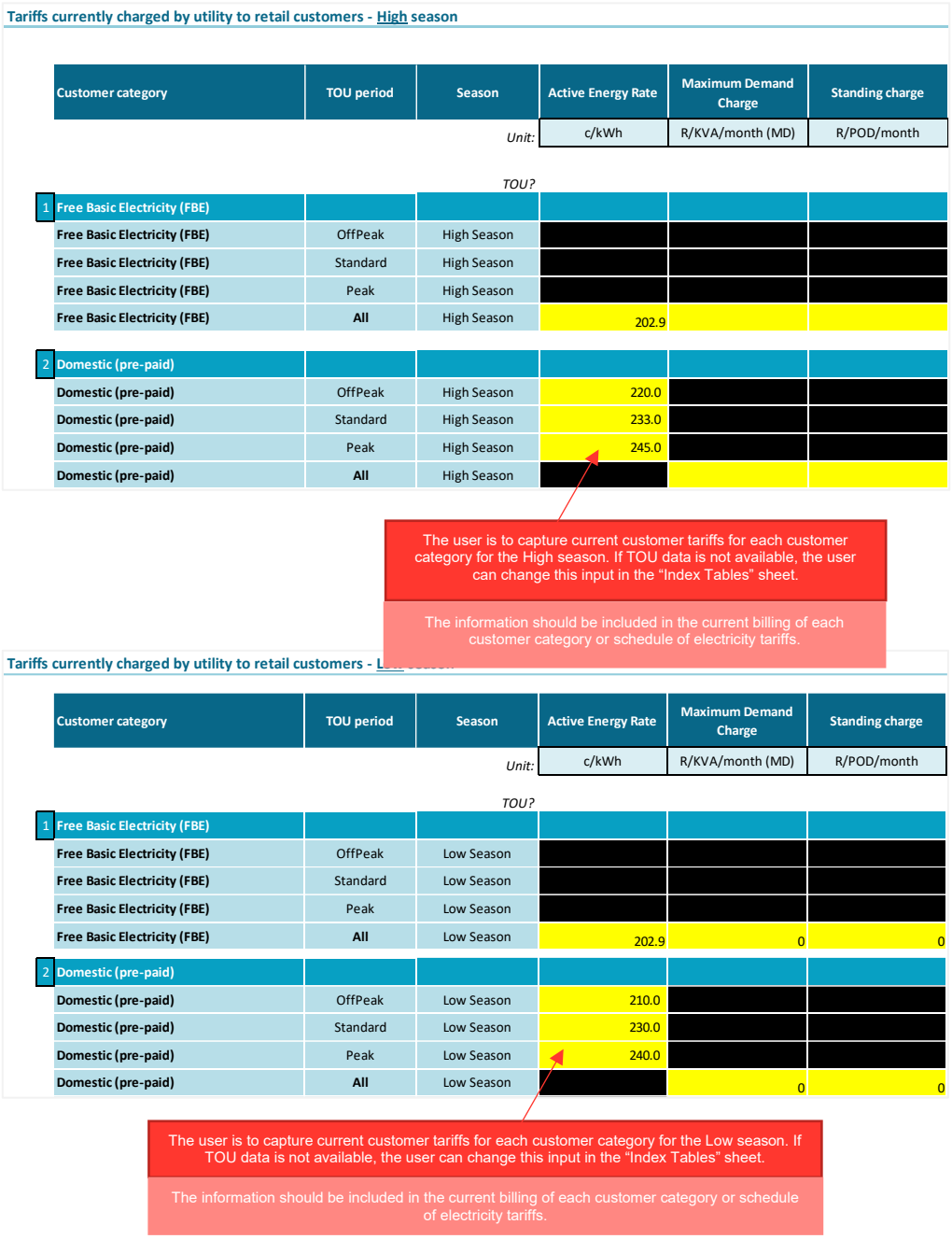
The user must input the forecasted amount in Rands of other capital investment not related to network assets.

The information should be included in the business plan of the utility.



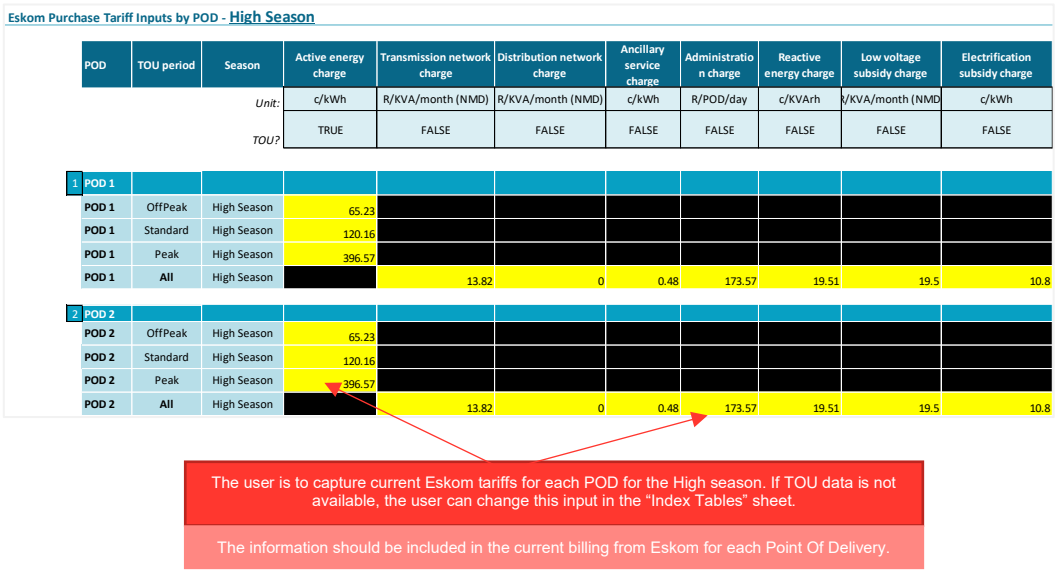
3.1.10 End-User Tariffs

The user is expected to capture the tariffs that apply to various customer categories during the High and Low seasons.



3.1.11 Eskom Tariff Inputs

The user is expected to capture the tariffs that apply to various PODs during the High and Low seasons. This can be done manually as detailed below or using the “Eskom rates add-on” as mentioned in Section **Error! Reference source not found.**. Please refer to the “Eskom rates add-on” training video embedded in Section **Error! Reference source not found.** for more information on this.

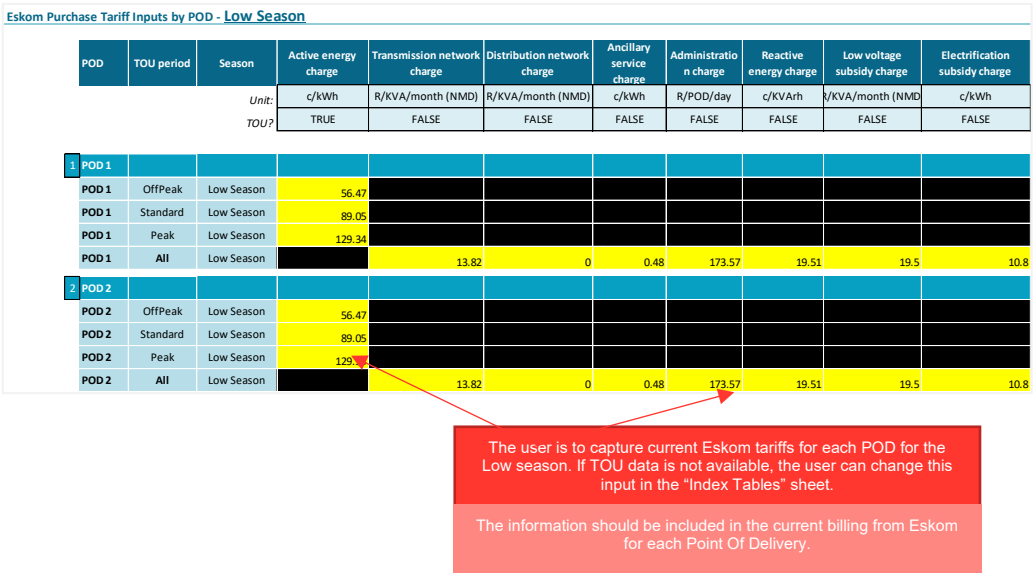


Eskom Purchase Tariff Inputs by POD - High Season

	POD	TOU period	Season	Active energy charge	Transmission network charge	Distribution network charge	Ancillary service charge	Administration charge	Reactive energy charge	Low voltage subsidy charge	Electrification subsidy charge
			Unit:	c/kWh	R/KVA/month (NMD)	R/KVA/month (NMD)	c/kWh	R/POD/day	c/KVArh	R/KVA/month (NMD	c/kWh
			TOU?	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
1	POD 1										
	POD 1	OffPeak	High Season	65.23							
	POD 1	Standard	High Season	120.16							
	POD 1	Peak	High Season	396.57							
	POD 1	All	High Season		13.82	0	0.48	173.57	19.51	19.5	10.8
2	POD 2										
	POD 2	OffPeak	High Season	65.23							
	POD 2	Standard	High Season	120.16							
	POD 2	Peak	High Season	396.57							
	POD 2	All	High Season		13.82	0	0.48	173.57	19.51	19.5	10.8

The user is to capture current Eskom tariffs for each POD for the High season. If TOU data is not available, the user can change this input in the “Index Tables” sheet.

The information should be included in the current billing from Eskom for each Point Of Delivery.



Eskom Purchase Tariff Inputs by POD - Low Season

	POD	TOU period	Season	Active energy charge	Transmission network charge	Distribution network charge	Ancillary service charge	Administration charge	Reactive energy charge	Low voltage subsidy charge	Electrification subsidy charge
			Unit:	c/kWh	R/KVA/month (NMD)	R/KVA/month (NMD)	c/kWh	R/POD/day	c/KVArh	R/KVA/month (NMD	c/kWh
			TOU?	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
1	POD 1										
	POD 1	OffPeak	Low Season	56.47							
	POD 1	Standard	Low Season	89.05							
	POD 1	Peak	Low Season	129.34							
	POD 1	All	Low Season		13.82	0	0.48	173.57	19.51	19.5	10.8
2	POD 2										
	POD 2	OffPeak	Low Season	56.47							
	POD 2	Standard	Low Season	89.05							
	POD 2	Peak	Low Season	129.							
	POD 2	All	Low Season		13.82	0	0.48	173.57	19.51	19.5	10.8

The user is to capture current Eskom tariffs for each POD for the Low season. If TOU data is not available, the user can change this input in the “Index Tables” sheet.

The information should be included in the current billing from Eskom for each Point Of Delivery.

3.1.12 FBE Inputs

The user is to capture information relating to subsidies for the various years and how these subsidies are allocated to different customer categories.

The label of the subsidy should be inserted here

The value of the subsidy and forecast should be inserted here

Direct subsidies

Types of subsidies		Value in Year 1	Value in Year 2	Value in Year 3	Value in Year 4
Free Basic Electricity		R -	R -	R -	R -
		R -	R -	R -	R -
		R -	R -	R -	R -
		R -	R -	R -	R -
		R -	R -	R -	R -
Total		R -	R -	R -	R -

Allocation of direct subsidy benefits by customer category

	Customer Categories	Weighting factor	Monthly consumption per POD fully discounted (kWh/month/POD)
1	Domestic (pre-paid)	1	50
2	Domestic (conventional)	0	
3	Agriculture	0	
4	Mining & quarrying	0	

The allocation of subsidies along with the monthly consumption in kWh /month/POD allocated to the subsidy should be inserted here