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Abstract

The assumption that electricity consumers have no alternative but the grid for their electricity needs is currently being challenged by affordable Behind-The-Meter (BTM) technologies such as distributed PV systems and batteries. This shake-up has been well documented in liberalized power markets such as Europe, North America, and Australia. This paper looks at the regulatory implications of BTM technologies in Africa, where the power industry often follows the Single Buyer Model. Applying a game-theoretical model, we illustrate the impact of BTM technology adoption on different consumer classes under different end-user rate designs and BTM technology cost scenarios. In our analysis, we focus on the following regulatory metrics: cost efficiency, equity, and cost recovery. We find that with the increasing penetration of BTM technologies the popular volumetric increasing block tariff design leads to a regulatory trilemma between equity, the recovery of the integrated Distribution and Supply Companies' (DISCOs) costs, and the recovery of the costs of the Single Buyer Entity, being responsible for the procurement of energy and the planning, dispatch, and the expansion of the transmission grid. We argue that it is important to transition to an end-user rate design with increased fixed charges. We propose that fixed charges be differentiated based on historical consumption, serving as a proxy for income. We offer several recommendations on how to overcome practical difficulties when implementing such charges. However, merely revising the end-user rate design might not be enough, the penetration of BTM technologies is an additional argument for wider reforms.

Keywords

End-user rate design; Solar PV; Batteries; Regulation; Africa

1. Introduction[*]

Household adoption of solar PV has proved significant in liberalised power markets as in Europe, North America, and Australia (Lukanov and Krieger, 2019; Fraunhofer, 2020; Simshauser, 2016). Under a volumetric electricity tariff (in €/kWh consumed), the reduced net load enabled by the installation of solar PV presents a challenge to cost recovery for regulated utility investments. As a result, there has been an extensive debate about how to redesign network charges, the regulated part of the electricity bill in a liberalised power system: see e.g. Eid et al. (2014), Schittekatte et al. (2018), and Simshauser (2016).

In Africa, small-scale stand-alone PV systems have been promoted so far for mini-grid service in rural communities as well as for other community services, such as street lighting, solar kiosks, mobile-phone charging stations, telecom towers, and water pumps (IRENA, 2015). Currently, as for example, discussed in Candas et al. (2019) and Young et al. (2019), investments in small-scale solar PV can be profitable even without any additional policy incentives, depending mostly on the solar irradiation and the end-user rate design. In that respect, the rise of African prosumer households should be expected. There are several specifically African features of PV adoption worth highlighting. In this paper, we mainly consider the following four factors. First, in Africa, not only the network charges, but the entire end-user electricity rate is typically regulated. Second, a different regulatory model for the power system is in place when compared to the well-researched European, North American, or Australian context. Different actors under the African regulatory model, which often takes the form of a Single Buyer Model, are affected in financial terms by increased BTM technology adoption by households and might require different solutions. Third, the African context requires a tailored analysis due to socio-economic differences. The current rate design relies on high-consumption, often wealthier, consumers to carry a more than proportional share of the electricity costs. Fourth and last, there are also infrastructure differences. For example, smart meters have been little used to date. Not having smart meters limits the possible options for end-user rate design.

Keeping in mind these important differences, in this paper we aim to answer the following two questions:

- What are the regulatory implications of the increased adoption of BTM technologies under the current end-user rate design?
- Can we mitigate possible concerns through an improved end-user rate design? Or are wider reforms deemed necessary?

To better understand the consequences of BTM technology adoption on electricity rates and financial flows between relevant actors under the Single Buyer Model, we introduce a game-theoretical modelling framework based on Schittekatte et al. (2018). We firm up our analysis by the application of our modelling to a case study representing the recently announced tariff plan (2020/2025) for Egypt. In our analysis, we consider three metrics quantifying regulatory objectives: cost efficiency, equity, and cost recovery for the regulated entities. Applying the game-theoretical model using Egyptian data, we compute these regulatory metrics for the increasing block tariff (IBT) design, which is in use now, and a proposed alternative, in which we allocate an important share of the regulated costs via fixed charges to the end-user. Inspired by Battle et al. (2020), Borenstein (2020), and Burger et al. (2020), the proposed fixed charges are differentiated based on historical consumption levels proxying income. We compute

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the results under two BTM technology cost scenarios to test the robustness of the alternative end-user rate designs.

In what follows, we first position the paper in the wider literature and describe the African context in more detail. Second, we introduce our modelling approach. Third, we describe the data for the Egyptian case study. Fourth, we discuss the results of the case study in terms of the different end-user rate designs. Lastly, we offer a conclusion.

2. Positioning and context of the paper

In this section, we first provide a literature review discussing the impact of the adoption of BTM technologies on end-user rate design in the context of liberalised wholesale and retail electricity markets. Second, we explain how the typical African regulatory model differs.

2.1 Impact of BTM technologies on network charge design in liberalised (retail) markets

In the European Union (EU), after the entry into force of the Second Energy Package in 2003 (Directive 2003/54/EC), all consumers were free to choose their electricity retailer from a wide range of competitors.[1] The Third Energy Package adopted in 2009 requires legal unbundling for electricity distribution from generation and supply activities (Meeus, 2020). DSOs are responsible for planning and operating distribution networks, while retailers oversee the supply of electricity to final consumers through a combination of long-term contracts, short-term wholesale markets, and/or their generation portfolio. Similarly, in Australia and several states in the US (e.g. Texas and California), retail markets for consumers were set up as described in Defeuilley (2009). In this liberalised setup, the final electricity bill typically has three parts: energy costs, network charges, and taxes and levies. The energy costs depend on the retail contract offered by competing retailers with limited or no intervention from the regulatory authorities. The network charges allow the remuneration of DSOs and TSOs for their efficiently incurred costs and are set by the regulator. Taxes and levies are determined by the relevant legislators. Most academic research investigating the impact of BTM technology adoption has focussed on the design of the regulated network charges. We cannot cover all papers as this topic has attracted a good deal of writing. Instead, we select several studies covering different jurisdictions and applying different methodologies.

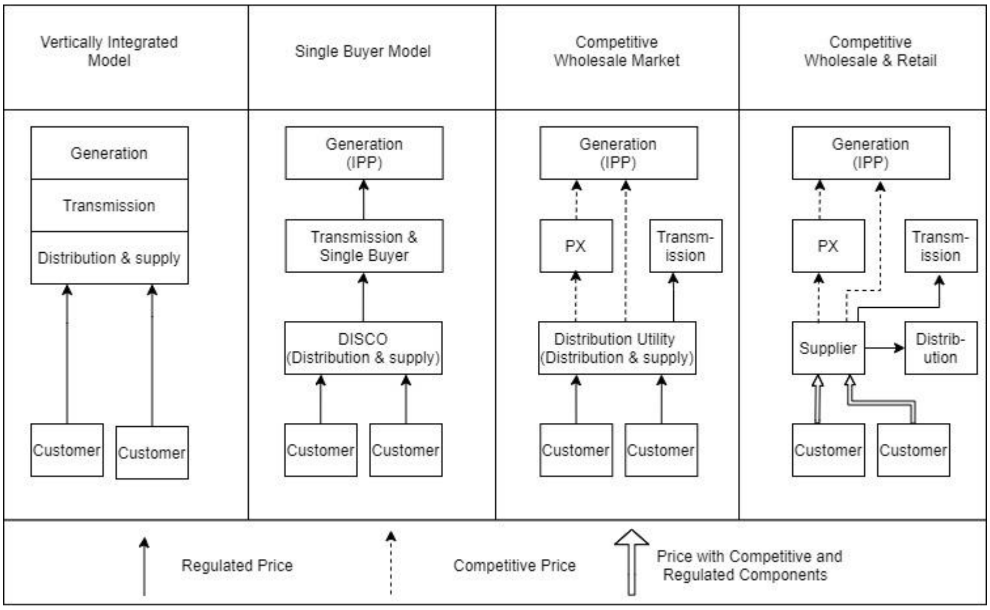
Several contributions apply simulation models to test how network costs are redistributed among consumers (with and without BTM technologies) when the network tariff structure is changed. An example is a paper by Eid et al. (2014). The challenges posed by consumers investing in PV and batteries in terms of cost recovery of regulated network investments are analysed for Spain using a simulation model. Simshauser (2016) focuses on Australia and applies a simulation to demonstrate how a peak capacity-based ‘demand tariff’ would be more efficient, cost-reflective, and have more equitable pricing structures than volumetric tariffs with net-metering. Other papers more explicitly consider the economic efficiency of a network tariff design and the redistributive effects. For example, Abdelmotteleb et al. (2017) propose a network tariff design that includes forward-looking peak-coincident network charges plus fixed charges based on the Ramsey principle, using a simulation model endogenously considering consumer investments. Finally, Schittekatte et al. (2018) model DSO cost recovery using a non-cooperative game between consumers equipped with solar PV and batteries. This is done to show the strategic behaviour of active consumers as a function of different network tariff structures.

[1] In some Member States consumers were free to choose a retailer a long time before. For example in the Great Britain this was possible as early as 1999 (Ofgem, 2020).

2.2 The African regulatory model

In a recent report by the African Development Bank (AFDB, 2019) it is noted that while private sector participation is being encouraged, power systems in Africa largely retain characteristics of the traditional integrated monopoly utility structure. The countries that have started unbundling have separated the integrated utility into entities for the generation, the transmission, and the distribution and supply of electricity. Such setups are typically variants of the Single Buyer Model as described in more depth in Eberhard et al. (2005). It is the Single Buyer Model that we focus on in this paper. Figure 1 schematically illustrates the resulting cash flows in the Single Buyer Model and its alternatives. The Single Buyer Model can be seen as an intermediate regulatory model between the vertically integrated and the competitive wholesale model.

Figure 1: 'Typical' regulatory models and resulting cash flows. Edited figure inspired by Eberhard et al. (2005).



Under the Single Buyer Model, a typically state-owned Single Buyer Entity is designated to buy energy from Independent Power Producers (IPP) competing for Power Purchase Agreements (PPAs). Besides the procurement of energy, this entity owns the transmission network, oversees dispatch and system operation, and carries out the responsibility for planning both the long and short term. The popularity of the Single Buyer Model can be explained by the fact that this model allows governments to retain strong influence over the security of supply and system planning, while promoting private investments in generation and/or distribution. On the generation side, in more than 30 African countries, IPPs have been investing in generation assets after concluding long-term PPAs with the Single Buyer Entity. On the distribution side, in 2017, there were investor-owned DISCOs in nine countries, namely: Cameroon, Ivory Coast, Egypt, Morocco, Namibia, Nigeria, South Africa, Uganda, and Zambia (AFDB, 2019; EgyptERA, 2020a). For example, at the time of writing, EgyptERA (2020a) reports more than 50 investor-owned DISCOs alongside state-owned distribution utilities under Egypt's current Single Buyer Model.

In terms of financial flows, in the Single Buyer Model, long-term PPAs remunerate IPP's capital costs through mechanisms such as a take-or-pay clause or a fixed component in the price formula (Kessides, 2004). The Single Buyer Entity charges the costs of these long-term PPAs along with its transmission costs to its (captive) customers, most importantly, regulated DISCOs, and large grid users (Rudnick and Velasquez, 2018; Besant-Jones, 2006). The regulated charge that the DISCOs pay to the Single Buyer Entity for the supplied energy is often called "the transfer price". For example, in Egypt, the transfer price consists of two components: a volumetric (per kWh) and a capacity-based (per kW) charge. The recovery of all the Single Buyer Entity's costs is guaranteed by the fact that the DISCOs, whether state or investor-owned, are only allowed to cover their energy needs by buying energy from the Single Buyer Entity at the transfer price.[2] Similarly, DISCOs enjoy a monopoly of energy supply to their electricity customers, who are subject to a regulated end-user tariff, see e.g. Hasan et al. (2020). The regulated end-user tariff reflects the DISCO's cost in terms of the distribution network, supplier activities such as billing, and the cost of energy supply incurred by purchasing from the Single Buyer Entity at the transfer price. Typically, the integral tariff is a large volumetric charge with increasing blocks (the charge per kWh increases with consumption) and a small fixed charge (per connection point). Thus, the DISCO is subject to regulated prices both upstream, in the form of the transfer price, and downstream, in the form of the regulated end-user tariff.

BTM technologies present a challenge to the recovery of regulated utility investments with popular predominantly volumetric end-user charges. This challenge is also reliant on local conditions. In what follows, we investigate in the context of the Single Buyer Model whether the investor-owned DISCOs that are unbundled from the Single Buyer Entity are under increased financial stress compared to their counterparts in other regulatory models. Specifically, these investor-owned DISCOs are the focus of the study since other publicly-owned DISCOs, integrated within the vertically integrated utility, can enjoy cross-subsidization from other activities softening any adverse financial impact of BTM technology adoption. Examples of other papers discussing end-user rate design in the context of a vertically integrated monopoly are Reneses et al. (2011) and Brown and Sappington (2017). Reneses et al. (2011) discusses end-user rate design for the vertically-integrated monopoly in Libya, but without considering the adoption of BTM technologies. Brown and Sappington (2017) estimate, meanwhile, the welfare and distributional impact of increased penetration of solar PV under volumetric net-metered charges in a vertically integrated North American utility.

3. Methodology

We have split this section into four parts. First, we introduce the modelling approach. Second, we provide the mathematical formulation. Third, we discuss the solution approach. Fourth, we explain how we derive metrics from the output of the model to proxy regulatory objectives.

3.1 Modelling approach

Inspired by Schittekatte et al. (2018), the model captures possible regulatory challenges resulting from the penetration of BTM technologies. The model is set up as a stylized game with two levels: an upper-level cost recovery constraint; and a lower-level optimization problems. Using a similar mathematical formulation, specific aspects of the network tariff design problem in the European context have been studied in, for example, Govaerts et al. (2019), Hoarau and Perez (2019), Schittekatte and Meeus (2020), Nouicer et al. (2020) and Askeland et al. (2020).

To represent the Single Buyer Model, it was necessary to make several changes to the formulation as it appeared in Schittekatte et al. (2018) and the above-mentioned papers. In the context of this paper, the regulated DISCO collects all regulated end-user charges from the consumers and pays the transfer price, consisting of a volumetric and capacity part, to the Single Buyer Entity (as also illustrated in Figure 1). In contrast, in the model by Schittekatte et al. (2018) the DSO receives the income from the network charges via the retailer, which is in charge of billing. Further, in Africa , there are additional socio-economic considerations that shape the ("default") rate design. Namely, in many countries, a (volumetric) Increasing Block Tariff (IBT) is in place with different consumer classes paying different

[2] Typically, DISCOs procure energy at a regulated transfer price from the Single Buyer Entity. Exceptionally, under certain circumstances, DISCOs can procure energy from other DISCOs (EgyptERA, 2020c).

average rates per kWh consumed. Therefore, to capture these socio-economic considerations, we model differentiated consumer classes based on different consumption levels. In most EU countries, residential consumers often pay the same flat volumetric rate per kWh consumed. The reason is that the differences in terms of wealth and consumption between different residential users are less notable.

To answer the two main research questions of this paper, we investigate the default volume-based IBT design and a proposed alternative under two different BTM technology cost scenarios. The alternative end-user rate design consists of a flat volumetric rate and differentiated fixed charges. To analyse and compare the results, we develop a set of metrics that represents the core regulatory principles when designing end-user rates. The metrics are cost efficiency, equity and cost recovery (see further Section 3.4).

3.2 Mathematical formulation

In this stylized game, the regulatory cost recovery requirement for the regulated DISCO is represented as an upper-level constraint. Costs are allocated according to the two different end-user rate designs. In turn, the lower-level problems represent consumers. Consumers representing a consumer class can be passive consumers or prosumers attempting to reduce their annual energy costs. Those prosumers can do so by investing in BTM technologies when profitable, while respecting the energy demand balance and the technical constraints of BTM technologies. We start by introducing the optimization problem of the prosumers. After, we elaborate upon the upper-level cost recovery constraint. All variables are put in italics while parameters are not. Also, please note that all costs and revenues are annualized. Hourly time steps are considered.

3.2.1 Lower-level consumers representation

In terms of consumers, passive consumers are inelastic while prosumers respond to price signals.[3] Prosumers can do so by combining the electricity procured from the DISCO paid via the electricity bill (AUB_i) and investment in BTM technologies (AIC_i), whatever is optimal to minimize their annual electricity costs ($IAEC_i$) as per Eq. (1).

$$Minimize: IAEC_i = AIC_i + AUB_i \qquad \forall\, i \tag{1}$$

Given that the considered BTM technologies are solar PV and batteries, the annualized investment cost (AIC_i) for consumer (i) consists of two components, as shown in Eq. (2). The first is the cost of the solar PV system calculated as the product of the annualized investment cost per kWp (APC) and the installed capacity ($ICPV_i$). The second is the cost of the installed battery calculated as the product of the annualized investment cost per kWh capacity (ABC) and the maximum volume of energy that can be stored in the installed battery ($SoCmax_i$). Passive consumers' annualized BTM technology investment costs are always zero. Consumers are passive because of a lack of financial resources, an underdeveloped investment appetite, ignorance of their electricity bill, or practical issues such as insufficient space on their roof.

$$AIC_i = ICPV_i * \mathrm{APC} + SoCmax_i * \mathrm{ABC} \qquad \forall\, i \tag{2}$$

The electricity bill (AUB_i) is the summation of two terms, highlighted in Eq. (3). For simplification, the model annualizes the costs by using representative days weighted by a factor (W). M stands for the number of months in a year. The first term $GW_{t,i}$ represents the withdrawn energy from the grid by consumer (i) at each time step (t) and $GI_{t,i}$ the energy injected into the network. The default implemented

[3] Passive consumers can also see changes in their electricity bill due to a change in the rate design and the actions of prosumers which can lead to cost shifts between different consumers.

rate design takes the form of an IBT ($R_{v,i}$), an increasing charge per kWh consumed, and a minor fixed monthly charge ($R_{f,i}$).[4] GC_i is a binary variable equal to 1 if the consumer is grid-connected and equal to zero when the consumer decides to go off-grid. For the proposed alternative end-user rate design, $R_{v,i}$ is not differentiated per consumer class but $R_{f,i}$ is. It should be noted that the modelling implementation of the IBT design is simplified. We assume that the reduced consumption of prosumers due to the installation of BTM technologies does not directly change the consumer class to which a prosumer belongs, and thus the corresponding tariff.[5] Not considering this effect might mean that we slightly underestimate the results, as discussed in Section 5.

In this model, metering is assumed to be carried out by mechanical meters that measure net consumption $\left(GW_{t,i} - GI_{t,i}\right)$. We consider AUB_i is a non-negative variable, in other words, the electricity bill cannot become negative.

$$AUB_i = \mathrm{M} * \left(\mathrm{W} * \sum_t \left(GW_{t,i} - GI_{t,i}\right) * R_{v,i} + R_{f,i} * GC_i\right) \quad \forall\, i \tag{3}$$

This optimization problem of the consumer is subject to the energy balance constraint as per Eq. (4). $BD_{t,i}$ is the power at which energy is discharged from the battery installed by prosumer (i) in (kWh/h) during time step (t). $\mathrm{PV_t}$ is the hourly output per kW of installed solar PV. On the other side of the equation, $GI_{t,i}$ is the power at which energy is injected into the grid during the time step (t) by consumer (i). $\mathrm{L_{t,I}}$ is the hourly load profile of the consumer representing a certain consumer class (i). $BC_{t,i}$ is the power at which energy is charged into the battery of prosumer (i) during time step (t) in (kWh/h). $Dump_{t,i}$ is the power dumped by the same consumer during the same time step.

$$BD_{t,i} + GW_{t,i} + ICPV_i * \mathrm{PV_t} = GI_{t,i} + \mathrm{L_{t,i}} + BC_{t,i} + Dump_{t,i} \quad \forall\, t, i \tag{4}$$

Additionally, there are some technical constraints described in Eq. (5-10). Eq. (5) states that the battery state of charge in any time step cannot exceed its maximum. Further, Eq. (6-7) specify the state of charge of the battery, Eq. (6) states that the state of charge ($SoC_{t,i}$) of a time step shall equal that of the previous time step ($SoC_{t-1,i}$) in addition to the (dis)charged energy during this time step (Δt) considering (ɿc and ɿd) the charging and discharging efficiency. Furthermore, Eq. (8-9) states that the battery's (dis)charging capacities ($BD_{t,i}$and $BC_{t,i}$) should be less than the maximum storage capacity of the battery ($SoCmax_{\,i}$) multiplied by the inverse of the minimum full (dis)charge duration ($\mathrm{Bmax}_{\,\mathrm{i}}$) at any time step. Eq. (10) should ensure that all lower-level variables are non-negative.

$$SoC_{t,i} \leq SoCmax_{\,i} \quad \forall\, t, i \tag{5}$$

$$SoC_{t,i} = SoC_{t-1,i} + \text{ɿc} * BC_{t,i} * \Delta\mathrm{t} - BD_{t,i} * \frac{\Delta\mathrm{t}}{\text{ɿd}} \quad \forall t \neq 1, i \tag{6}$$

$$SoC_{t=1,i} = SoC_{t=max,i} \quad \forall i \tag{7}$$

$$BD_{t,i} \leq SoCmax_{\,i} * \mathrm{Bmax_i} \quad \forall\, t, i \tag{8}$$

$$BC_{t,i} \leq SoCmax_{\,i} * \mathrm{Bmax}_{\,\mathrm{i}} \quad \forall\, t, i \tag{9}$$

$$SoC_{t,i}, ICPV_i, SoCmax_{\,i}, GW_{t,i}, GI_{t,i}, BD_{t,i}, BC_{t,i}, Dump_{t,i} \geq 0 \quad \forall\, t, i \tag{10}$$

Besides, binary variables are used to ensure neither coincident battery charging and discharging ($BD_{t,i}$ and $BC_{t,i}$), nor withdrawal and injection into the network ($GW_{t,i}$ and $GI_{t,i}$). They also ensure that

[4] Please note that $R_{v,i}$ and $R_{f,i}$ are variables of the upper-level problem, not of the lower-level consumer problem. As explained in the solution approach in Section 3.3., $R_{v,i}$ and $R_{f,i}$ are plugged in as parameters in the lower-level problem. As such, the lower-level problem is a Mixed Integrated Linear Problem (MILP).

[5] One can also interpret this as if there is a time lag between reducing the annual consumption to end up in a different consumer class and the change of the average price per kWh consumed of that new consumer class.

the injection and withdrawal from the network are forced to zero in case a consumer goes off-grid (GC_i being 0).

3.2.2 Upper-level regulated costs recovery representation

In contrast to the liberalised context, the regulated costs of the DISCO (RC_{DISCO}) are not limited to its (annualized) network costs ($\mathrm{SC_{DISCO}}$). Indeed, as shown in Eq. (11), RC_{DISCO} consists of $\mathrm{SC_{DISCO}}$ and the transfer price payments to the Single Buyer Entity (WP_{SB}) to fulfil its supply obligations. It should be noted that the network costs of the DISCO are considered to be sunk and include remuneration for these regulated costs. WP_{SB} can be obtained knowing the volumetric component and the monthly capacity component of the transfer price in Eq. (12), respectively $\mathrm{TP_v}$ and $\mathrm{TP_c}$. $L_{DISCO,t}$ represents the total DISCO load at each time step and $Lmax_{DISCO}$ is the maximum total DISCO load, as obtained by Eq. (13 - 14).

$$RC_{DISCO} = \mathrm{SC_{DISCO}} + WP_{SB} \tag{11}$$

$$WP_{SB} = \mathrm{M} * \left((Lmax_{DISCO} * \mathrm{TP_c} + \sum_t \mathrm{W} * \left(L_{DISCO,t} * \mathrm{TP_v} \right) \right) \tag{12}$$

$$L_{DISCO,t} = \sum_i (GW_{t,i} - GI_{t,i}) \ \forall t \tag{13}$$

$$L_{DISCO,t} \leq Lmax_{DISCO} \quad \forall t \tag{14}$$

On the revenue side of the DISCO, Eq. (15) shows that the DISCO's collected revenues (CR_{DISCO}) is the summation of consumer bills (AUB_i). Eq. (16) represents the cost recovery equilibrium constraint stating that the DISCO's costs (RC_{DISCO}) should equal its revenues (CR_{DISCO}).

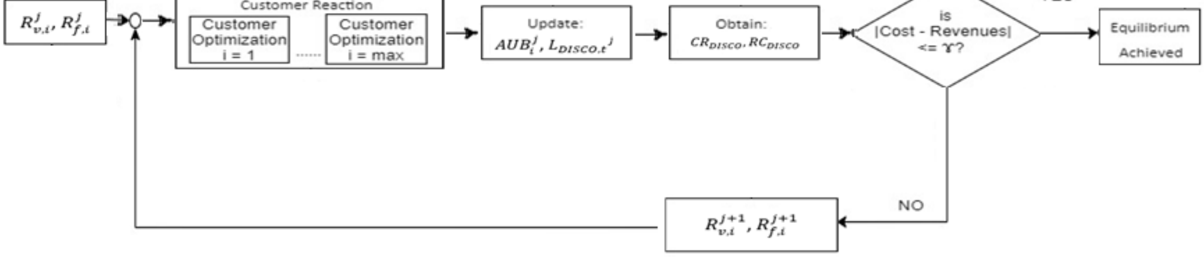
$$CR_{DISCO} = \sum_i (AUB_i) \tag{15}$$

$$CR_{DISCO} = RC_{DISCO} \tag{16}$$

3.3 Solution Algorithm

In terms of the solution algorithm, the equilibrium between the upper-level cost recovery constraint and the lower-level optimization problems, representing different consumers, is obtained through iterations between the two levels as illustrated below in Figure 2. The equilibrium is reached when all regulated costs are recovered, and when consumers have no incentive to change their decisions.

Figure 2: Solution algorithm for the stylised game



As presented in Figure 2, we start with the baseline conditions in the first iteration (j =1). For each iteration, the reaction of the consumers to the end-user rate is calculated. After, the DISCO residual and maximum load and the collected DISCO revenues are calculated. Then, the collected revenue is compared to costs incurred by the DISCO to check whether the cost recovery constraint has been fulfilled. If not, the volumetric charge ($R_{v,i}^{j}$), in case of the current IBT end-user rate design, or the fixed charge ($R_{f,i}^{j}$), in case of the alternative end-user rate design, is increased with a small increment until the equilibrium as expressed in Eq. 16 holds. Importantly, when updating the end-user charges to reduce the deficit in DISCO revenues, the rates of all consumer classes are increased proportionally.

The prosumer optimization model is implemented in the GAMS environment and linked to MATLAB in which the iterative solution algorithm, comprising the regulatory cost recovery constraint, is modelled (GAMS, 2020). The MILP optimization problems are solved using the CPLEX solver.

3.4 Regulatory Metrics

A set of regulatory metrics are developed to assess the performance of a rate design. These metrics represent the main regulatory principles of rate design namely cost efficiency, equity, and cost recovery: for more discussion see e.g. Schittekatte (2020) and Battle et al. (2020).

The first principle is cost efficiency. Cost efficiency for end-user rates has not generated much concern in the past since consumers did not have many options other than being passively supplied from the grid. However, with BTM technologies, this is no longer true. In such context, cost efficiency refers to the degree that economic signals, in this case, the end-user rate, align the interest of private consumers with that of the system, i.e. that maximizes social welfare (Schweppe et al., 1988). We measure the efficiency concerns as shown in Eq. (17). A negative efficiency concern implies a reduction in total system costs.

$$Efficiency\ Concerns = \frac{Total\ Sys\ Costs^{Equilibrium} - Total\ Sys\ Costs^{Baseline}}{Total\ Sys\ Costs^{Baseline}} * 100\% \quad (17)$$

Where, $Total\ Sys\ Costs^{Equilibrium}$ represents total system costs when the equilibrium is achieved. $Total\ Sys\ Costs^{Baseline}$ represents total system costs in the baseline i.e. the total system costs without any investment in BTM technologies under the default IBT design. These total system costs can be obtained from Eq. (18). $\mathrm{SC_{DISCO}}$ and $\mathrm{SC_{SB}}$ represents respectively the annualized sunk network cost of the DISCO and the annualized DISCO share of contribution to all sunk costs of the Single Buyer Entity.[6] $TVGC^{j}$ represents the total annual variable generation cost of the energy supplied. $TVGC^{j}$ can be estimated as the product of the DISCO residual load $L_{DISCO,t}{}^{j}$ times the weighted average generation cost (WGC), as per Eq. (19). The last term ($\sum_i AIC_i{}^{j}$) represents the investment costs of BTM technologies installed by consumers. In the baseline scenario, this term is zero.

$$Total\ Sys\ Costs^{j} = \mathrm{SC_{DISCO}}^{\mathrm{j}} + \mathrm{SC_{SB}}^{\mathrm{j}} + TVGC^{j} + \sum_{i} AIC_i{}^{j} \quad (18)$$

$$TVGC^{j} = \mathrm{WGC} * \sum_{t} L_{DISCO,t}{}^{j} \quad (19)$$

[6] The Single Buyer Entity's cost structure consists of the mostly sunk transmission network costs, capacity payments, and variable generation costs (in case the Single Buyer Entity also owns and operates generation) and the variable remuneration to IPP for electricity generated settled through PPAs. For simplicity, we do not make the distinction between integrated generation and IPPs, instead we introduce an estimated weighted average generation cost.

The second principle, equity, can be interpreted in many ways. In this paper, we choose the interpretation found in the work of Batlle et al. (2020). Equity, for us, refers to the degree that certain consumer categories, namely low-income consumers, are protected against the negative distributional impact of a rate design adjustment. Therefore, we calculate the equity concerns as the percentage change for the low-consumption consumer classes' ($i \epsilon s_{min}$) annual utility bills in equilibrium compared to the baseline bill, i.e. the electricity bill under the default IBT design with no consumer investing in BTM technologies. Eq. (20) specifies this calculation. A negative equity concern refers to a reduction of the electricity bill for the low-consumption consumer class.

$$Equity\ Concerns\ = \frac{\sum_i \left(AUB_i^{Equilibrium}\ -\ AUB_i^{Baseline}\ \right)}{\sum_i AUB_i^{Baseline}} * 100\% \quad i\ \epsilon\ s_{min} \tag{20}$$

The last metric represents the cost recovery principle. This principle implies that tariffs shall allow the regulated entity to recover investments that were considered prudent and approved by the regulator (Reneses et al., 2013). Since both the income of the DISCO and the Single Buyer Entity are regulated, cost recovery is proxied by two different metrics.

With the DISCO, the first metric ($Cost\ Recovery\ Concerns_{DISCO}$) shows the ability of a certain end-user rate design to recover sunk DISCO investment costs (SC_{DISCO}). As shown in Eq. (21), the metric is quantified as the percentage cost recovery of SC_{DISCO}. It should be noted that, by construction, the algorithm ensures that DISCO cost recovery is reached. However, if cost recovery could not be achieved due to any reason such as complete grid defection, the algorithm stops while flagging a percentage deficit highlighting the DISCO cost recovery concern.

$$Cost\ Recovery\ Concerns_{DISCO} = \frac{\mathrm{SC}_{\mathrm{DISCO}} - (CR_{DISCO} -\ WP_{SB})}{\mathrm{SC}_{\mathrm{DISCO}}} * 100\% \tag{21}$$

Similarly, the second metric ($Cost\ Recovery\ Concerns_{SB}$) captures the ability of an end-user rate along with a transfer price design to recover the Single Buyer Entity's sunk investment cost (SC_{SB}). In other words, the metric illustrates concerns arising from the discrepancy between the cost structure of the Single Buyer Entity and its price structure. It is calculated as the recovered cost percentage of SC_{SB}as shown in Eq. (22). Any negative cost recovery concern refers to overcompensation of the respective regulated entity.

$$Cost\ Recovery\ Concerns_{SB} = \frac{\mathrm{SC}_{\mathrm{SB}} - (\ WP_{SB} -\ TVGC)}{\mathrm{SC}_{\mathrm{SB}}} * 100\% \tag{22}$$

4. Egyptian case study

We perform a case study focussing on Egypt to analyse the interaction between consumers investing in BTM technologies, the regulated end-user rate, and the impact on investor-owned DISCOs. More specifically, the case study uses the final year in the five-year Egyptian tariff plan (2020-2025) as a baseline to provide recommendations for the next five-years (2025-2030). As such, the presented data regarding the assumptions and boundary conditions need to be considered for this period.

Egypt was chosen as a case study for two reasons. First, there are relatively limited network costs to be recovered from the regulated end-user rate.[7] This implies that the conducted analysis might serve as

[7] Such relatively low sunk network costs in the final tariff are due to the fact that the allocation of much of these costs is carried out ahead, during the network development phase, via connection charges making use of standard network models

a warning that DISCOs with different cost structures could find themselves in a much more severe position. Secondly, as noted in Section 2.2, the Egyptian regulatory model managed to attract more than 50 investor-owned DISCOs as reported by EgyptERA (2020a). Therefore, the results of this paper can be usefully taken up by other countries that are planning to evolve in this direction. The following section is split into two parts. First, we describe the data related to the DISCO. After, we describe relevant consumer data.
relevant consumer data.

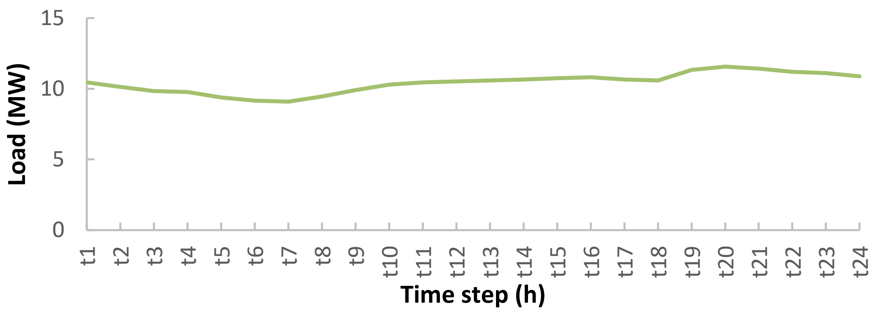
4.1 DISCO data

The DISCO data section is subdivided into the DISCO load profile and the regulated costs and prices.

4.1.1 DISCO load profile

The DISCO load profile is obtained in two stages. The first stage starts with obtaining the system load profile while the second calibrate it to the DISCO according to DISCO's annual energy sales, as detailed in Annex 1. There are varying sizes of licensed investor-owned DISCOs in Egypt, in this case study we assume a representative DISCO with annual energy sales of 90 GWh. Figure 3 displays the derived DISCO load profile for a representative day for the DISCO.

Figure 3: Derived DISCO load profile for a representative day



4.1.2 Regulated costs and prices

Table 1 indicates the regulated transfer price and relevant costs used in the case study. On the upstream side of the DISCO, the capacity-based component of the transfer price is 50 EGP/kW per month at the 66 kV voltage level and the volumetric component is 1.1 EGP/kWh (EgyptERA, 2020b).[8] The weighted average generation cost is 0.714 EGP/kWh (EgyptERA, 2017). On the downstream side of the DISCO, the weighted average end-user rate, including the small fixed charge, is 1.213 EGP/kWh (EgyptERA, 2020b). Using the previously introduced Eq. (11, 15, 16, and 18) and assuming that the allowed revenues are based on typical load profiles, we can deduct the sunk costs of the DISCO and the Single Buyer Entity. It should be noted that the Single Buyer Entity supplies multiple DISCOs. Therefore, SC_{SB} presents the share of the sunk costs of the Single Buyer Entity attributed to by the modelled DISCO.

(EgyptERA, 2020c). This can also be observed given that the weighted average end user rate is higher than the volumetric component of the transfer price with a relatively small amount as shown in Table 1.

8 In Egypt, the typical DISCO supplies its consumers at low or medium voltages. Exceptionally, DISCOs are allowed to contract generation capacity from other DISCOs to which they are connected but only if the contracted capacity is below 30 MW (EgyptERA, 2020c).

Table 1: DISCO and single buyer costs

Item	**Value**
Transfer Price - Volumetric component @ 66 kV (TP_v)	1.1 EGP/kWh
Transfer Price - Capacity component @ 66 kV (TP_c)	50 EGP/kW per Month
Weighted average system generation cost (WGC)	0.714 EGP/kWh
Weighted average end-user rate	1.213 EGP/kWh
Annualized DISCO sunk investment cost (SC_{DISCO})	3.12 EGP million/Annum
Annualized DISCO share of the Single Buyer Entity's sunk investment cost (SC_{SB})	41.7 EGP million/Annum

4.2 Consumer data

The consumer data section is subdivided into the consumer classes and BTM technology costs and parameters.

4.2.1 Consumer classes

The following analysis considers the fiscal year 2024/2025 as the baseline year, as the current tariff plan aims at achieving full cost recovery by that year with no external subsidy from the government (EgyptERA, 2020b). The implemented volumetric IBT rate design contains five consumption brackets with different volumetric charges per consumption bracket. Volumetric rates increase with consumption levels, as such high-consumption consumers often cross-subsidize poorer low-volume consumers. In Annex 2, there are listed the different volumetric end-user rates corresponding to different consumption levels, along with the respective volumetric charge.

For simplicity's sake and to make the tracking of the distributional impact easier, three consumer classes are modelled in this paper as shown in Table 2: the low consumption (S1); the medium consumption (S2); and the high consumption class (S3). The three middle consumer bands (2^{nd}, $3^{rd,}$ and 4^{th}) as shown in Table 7 of Annex 2 are aggregated into one consumer class. Also, to simplify matters, we use one average retail rate per consumer class instead of pricing the electricity progressively per consumption bracket. In this way, we make the analysis more comprehensible while not losing the main characteristic of the IBT design, namely that significant cross-subsidies exist between the different consumer classes. We briefly discuss the implications of this assumption in Section 5.1.2. The number of consumers per consumer class is scaled to the annual DISCO sales, while the relative size of these classes at the system level is taken into consideration as documented in EgyptERA (2020b). Finally, the representative consumption levels per consumer class are adjusted so that the weighted average end-user rate equals that of the system (1.213 EGP/kWh).

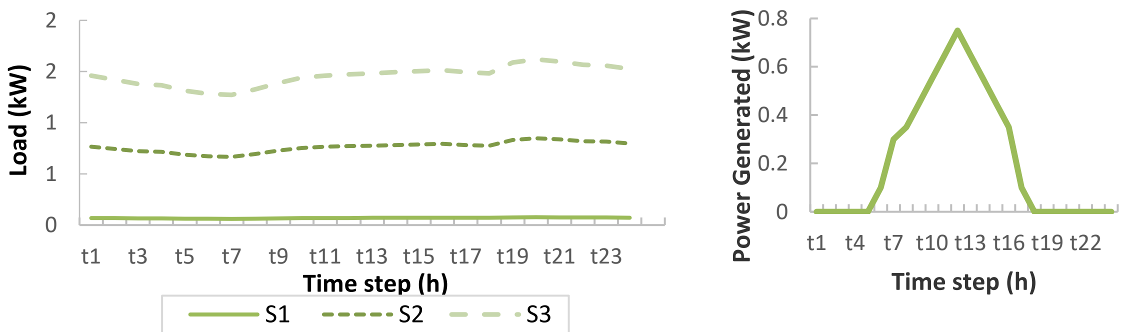
Table 2: Summarizing consumer classes' consumption and tariffs

Indicator	Unit	Consumer class		
		S1: Lowest-Consumption	S2: Medium-Consumption	S3: Higher-Consumption
Consumption span	(kWh/Month)	0 – 100	101 – 650	Above 650
Consumer share	(%)	26.4%	71.17%	2.43%
Number of consumers	Metering point	4603	12409	424
Representative consumption	(kWh/Month)	50	550	1050
	(kWh/Year)	600	6600	12600
Total consumption	(GWh/Year)	2.76	81.9	5.34
Consumption share	(%)	3.07%	91%	5.93%
Volumetric charge	(EGP/kWh)	0.71	1.17	1.45
Monthly volumetric costs	(EGP/consumer)	35.5	650.5	1522.5
Monthly fixed Charge	(EGP/consumer)	1	15	40
Monthly bill	(EGP/consumer)	36.5	665.5	1562.5
Modelled average rate	(EGP/kWh)	0.73	1.21	1.49
Planned contribution to total costs	(%)	1.85%	90.87%	7.28%

Interestingly, it can be seen from Table 2 that even though only 2.43% of all consumers belong to the high consumption class (S3), they represent almost 6% of total consumption and should cover 7.28% of all costs by paying the IBT rate. In contrast, the low consumption class (S1) contains 26.4% of all consumers but represents only 3.07% of total consumption and is intended to cover only 1.85% of all costs via the IBT rate. The consumers in the medium class (S2) represent the majority of consumers, consumption and cost contribution. They pay the weighted average electricity rate of the system and as such do not cross-subsidize the other consumer classes.

In terms of load profile, by defining the annual electricity consumption of the three consumer classes, we follow the same approach as explained in Annex 1 for the DISCO profile to obtain a typical-day load profile of a typical consumer per each consumer class. This profile is shown in Figure 4 (left). It is true that in doing so, we underestimate the variability in the individual consumer load. In Section 5.2.3, we discuss how this assumption impacts the results. Figure 4 (right) is introduced in the next subsection.

Figure 4: Left-Typical load profile for the three consumer classes (S1, S2, and S3). Right-Typical PV generation profile



An important assumption is that we assume that all consumers of the high consumption class and 25% of the consumers of the medium consumption class have the financial means to invest in BTM technologies when profitable. The other consumers are deemed passive.

4.2.2 BTM technology costs and parameters

In terms of the solar PV parameters, according to the global solar atlas (ESMAP, 2020), the average practical potential of utility-scale PV plants in Egypt is 5.247 kWh/kWp/Day. That is equivalent to an annual yield of around 1916 kWh/kWp. This kind of annual yield stands as an upper limit in terms of the model; the real yield will be below this level. This annual yield is modelled with a typical twenty-four-hour-day, as shown in Figure 4 (right). In terms of battery parameters, it is assumed to have a two-hour discharge duration, i.e. Bmax equal to 0.5. Also, charging efficiency and discharging efficiency are assumed to be, respectively, 95% and 90%.

In terms of costs, we construct two extreme cost scenarios for both BTM technologies, PV and battery storage. We do so to investigate the robustness of the rate design in achieving the regulatory objectives under different BTM technology cost scenarios. The high-cost scenario can be seen as cost estimates for 2025, while the low-cost scenario looks further ahead, circa 2030.

According to IRENA (2020), the global weighted average installation cost for utility-scale solar PV fell below 1000 US$/kW in 2019. Egypt also witnessed a reduction in investment costs including distributed roof-top applications which cost around 1000 US$/kW as confirmed by the media (Masrawy, 2017). On the other side, IRENA forecast that technological development will drive the PV CAPEX to fall into the 340 – 834 US$/kW range by 2030 (IRENA, 2019b). Therefore, for the lowest-cost scenario, it is assumed that the CAPEX will be 340 US$/kW. Regarding battery costs, IRENA (2019a), citing Ecofys et al. (2016), stated that the upfront cost of battery storage in 2025 will be between 300 and 400€/kWh. Other sources estimate that the cost will be much lower. However, we take the highest possible value for the high-cost scenario i.e. 400 €/kWh that is 472 US$/kWh assuming an exchange rate of 1.18 US$/€. For the low-cost scenario, we consider the lowest possible upfront cost for storage batteries in 2030, the final year in the study period. The two previously highlighted studies stated that the upfront cost of the storage battery in 2030 will go well below 300€/kWh. The low-cost scenario assumes an upfront cost of 100 US$/KWh, which is also assumed in Nouicer et al. (2020).

The annualized investment costs of both PV (APC) and battery (ABC) shown in Table 3 are obtained assuming a dollar conversion rate of 15.6 EGP/US$. A project lifetime for PV and batteries is assumed to be, respectively, twenty and ten years. While the project discount rate of PV and batteries are assumed to be, respectively, 15% and 10%.

Table 3: PV and battery storage cost scenarios

Scenario	Technology	CAPEX	Annualised CAPEX (APC- ABC)
High cost	PV	1000 US$/kW	2519 EGP/kWp-annum
	Storage	472 US$/kWh	1178 EGP/kW-annum
Low-cost	PV	340 US$/kW	857 EGP/kWp-annum
	Storage	100 US$/kWh	250 EGP/kW-annum

5. Results and discussion

The result and discussion section has two subsections. First, we present the results under the current IBT design in the two BTM technology cost scenarios. Then, second, we introduce an alternative proposal to the IBT design, the differentiated fixed charges (DFC) end-user rate design, and discuss its implications.

5.1 Volumetric Increasing Block Tariff (IBT)

We first describe the results starting with the high-cost BTM technology scenario. After, we discuss the results in a low- cost BTM technology scenario and elaborate upon the regulatory concerns that emerge.

5.1.1 Results under IBT for both cost scenarios

The modelling results applying the current IBT design and transfer price as described in Section 4 are shown in Table 4.

Table 4: Results of the IBT allocation methodology under the two BTM technology cost scenarios

Parameter / Variable / Regulatory Metric		High Cost	Low Cost
Volumetric Rate Component (EGP/kWh)	High – Consumption	1.48	1.52
	Medium -Consumption	1.20	1.24
	Low – Consumption	0.72	0.74
Fixed-Rate Component (EGP/Month)	High – Consumption	40	40
	Medium -consumption	15	15
	Low - Consumption	1	1
PV adoption per consumer high-consumption (kW)		6.7	6.7
Battery adoption per consumer high-consumption (kWh)		0	0
PV adoption per active consumer medium-consumption (kW)		0	3.5
Battery adoption per active consumer medium-consumption (kWh		0	0
Efficiency Concerns (%)		3.0%	-6.2%
Equity Concerns (%)		1.8%	4.6%
Cost Recovery Concerns of DISCO (%)		0%	0%
Cost Recovery Concerns of Single Buyer (%)		4.9%	23.9%

High cost BTM technology scenario

Under the high-cost BTM technology scenario, the IBT design in operation now presents limited regulatory concerns; the IBT rate does exactly what it is designed for, recovering the regulated costs in an acceptable manner.

However, in terms of efficiency, there are some concerns. The high consumption class installs enough solar PV to load defect due to the relatively high volumetric IBT rates for that class. As solar PV is more expensive than the centralised generation it is replacing in this scenario, there is an increase in system costs (+3%). In other words, due to the limited cost reflectiveness of the IBT design, the private benefit for the highest consumption class to install solar PV is higher than the system benefit; the high volumetric IBT rates combined with mechanical meters serve as an implicit subsidy for the adoption of solar PV. This is a well-known finding discussed, for instance, in Simshauser (2016) and Schittekatte et al. (2018). There is no business case for solar PV for active consumers in the medium consumption class, even though their end-user rates are slightly increased to cover up the loss of sales from the high consumption class. Further, there is no incentive to install batteries under a volumetric IBT end-user rate with mechanical meters.

In terms of cost recovery, as the share of consumers in the high consumption class is relatively limited, DISCO cost recovery is easily maintained by slightly increasing the volumetric rate for all consumer classes. This leads to a very limited equity concern of 1.8%. The Single Buyer Entity records a minor cost recovery concern (4.9%). This deficit is a consequence of the avoided revenues due to limited BTM technology adoption and a not fully cost-reflective transfer price (see further below).[9]

Low-cost BTM technology scenario

Under the low-cost BTM technology scenario, the situation looks different. Not only high but also active consumers in the medium consumption class find it now opportune to load defect.

In terms of efficiency, negative efficiency concerns (-6.2%) are shown in Table 4. This means a positive efficiency outcome with a reduction of 6.2% in total system costs. This outcome highlights that cheaper PV is replacing costly centralized generation.

In terms of equity, already a more severe level of equity concerns results. To maintain the cost recovery of the DISCO, the volumetric rates need to be proportionally increased by 4.8% for all consumer classes. An alternative to limit this equity concern would be only to increase the volumetric rate of the high consumption class. But this has no effect on DISCO cost recovery as all consumers in that class load defect and thus they do not contribute to cost recovery. Please note that the adoption of solar PV by active consumers in the medium consumption class is mainly driven by the decreased installation costs of solar PV. But PV adoption is also stimulated by increasing end-user rates to make up for the loss of sales in the high consumption class.

Surprisingly, what is most worrying in this low-cost BTM technology scenario is the cost recovery concern of the Single Buyer Entity. The capacity payment via the transfer price from the DISCO to the Single Buyer Entity remains the same as the adoption of PV does not affect the aggregated peak consumption of all consumers. However, due to the relatively high volume of decentralized generated electricity via solar panels, the Single Buyer Entity receives less revenue via the volumetric transfer price from the DISCO. As the sales via the volumetric transfer price are the main source of revenue for the Single Buyer Entity to pay out the PPAs for generating electricity and to finance its own sunk costs, a cost recovery issue occurs (23.9%). This kind of cost recovery gap is unsustainable for the regulated Single Buyer Entity and needs to be addressed. We do just this in the next subsection.

5.1.2 The regulatory trilemma under the IBT design in the low-cost BTM technology scenario

The reason for the cost recovery issue of the Single Buyer Entity is the fact that the transfer price function does not fully reflect its cost structure. The most straightforward way to correct this cost recovery issue is to set the volumetric transfer price equal to the short run marginal cost of generation, approximated by the weighted average variable generation cost (WGC). Remaining costs ($\mathrm{SC_{SB}}$) are recovered through a fixed component in the transfer price instead of as a capacity component.[10] The components of the transfer price paid by the DISCO to the Single Buyer Entity then becomes as shown in Eq. 23 and 24.

$$\mathrm{TP_v} = \mathrm{WGC} \tag{23}$$

$$\mathrm{TP_f} = \frac{\mathrm{SC_{SB}}}{12} \tag{24}$$

Re-running the model, considering the revised transfer price function brings us the results in Table 5.

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[9] The Single Buyer Entities' cost structure is assumed to be partly sunk and partly variable, while the transfer price is mainly volumetric and also has a capacity component (see e.g. Table 2 and footnote 6).

[10] Surely the average system running cost is not the optimal representation since it does not take into consideration the instantaneous variation of marginal system price. However, we employ this approximation given the lack of the relevant kind of information.

Table 5: Results of the IBT allocation methodology under the low-cost BTM technology scenarios with a cost-reflective transfer price

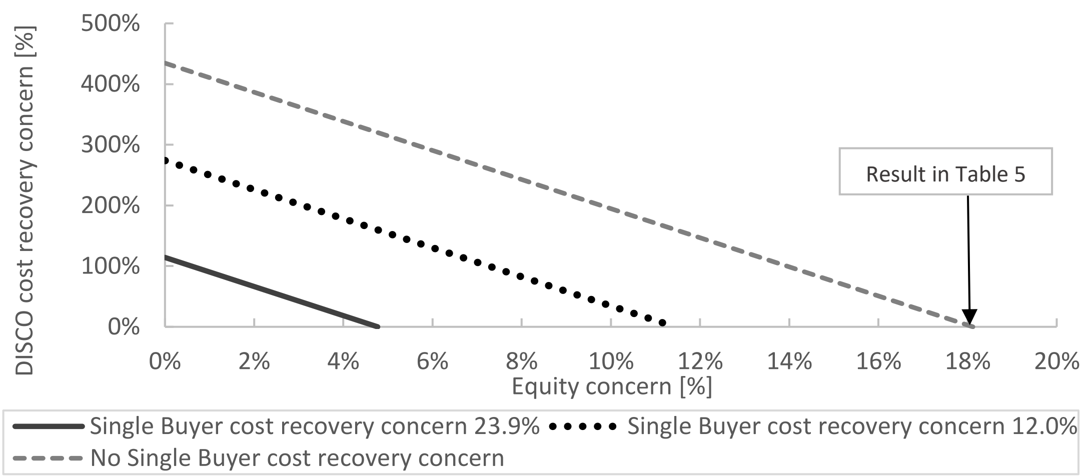
Parameter / Variable / Regulatory Metric		Low Cost
Volumetric Rate Component (EGP/kWh)	High-consumption	1.71
	Medium-consumption	1.40
	Low-consumption	0.84
Fixed-Rate Component (EGP/Month)	High-consumption	40
	Medium-consumption	15
	Low-consumption	1
Transfer Price Components	Volumetric (EGP/kWh)	0.714
	Fixed (M EGP/Month)	3.473
PV adoption per consumer high-consumption (kW)		6.7
Battery adoption per consumer high-consumption (kWh)		0
PV adoption per active consumer medium-consumption (kW)		3.5
Battery adoption per active consumer medium-consumption (kWh)		0
Efficiency Concerns (%)		-6.2%
Equity Concerns (%)		18.1%
Cost Recovery Concerns of DISCO (%)		0%
Cost Recovery Concerns of Single Buyer (%)		0%

In Table 5, by adjusting the transfer price function to Eq. 23-24, the Single Buyer cost recovery issue seems to be solved. However, by solving the Single Buyer cost recovery concern, the equity concern significantly increases. As the DISCO pays more to the Single Buyer Entity under the revised transfer price function, it has to raise the volumetric end-user rates to avoid a cost-recovery issue for itself. Consequently, an unsustainable equity concern of 18.1% results. One assumption leads to an underestimation of this effect, while one assumption can lead to an overestimation. Regarding the former, as already all active consumers in the middle consumption class load defected under the old transfer price, no change is found in terms of PV installed or efficiency concerns. The reason is that a static proportion of the medium consumption class is assumed to be active (25%), while in reality the active proportion would be dynamically driven by PV profitability. In that case, the efficiency metric would also change, and a spiral driven by more PV adoption due to increased rates would lead again to the need to further increase rates and so forth. This dynamic is known as the 'utility death spiral' (Castaneda et al. 2017). We should also note again here that by assuming one average retail rate per consumer class, instead of pricing the electricity progressively per consumption bracket, we risk some minor overestimation. More precisely, as more solar PV would lead to lower net consumption and thus a lower average price per kWh consumed, the incentive to install large PV installations might be dampened.[11]

In avoiding a death spiral, a compromise might be sought out between DISCO cost recovery, the Single Buyer Entity, and the equity concern. We can carry out this computation by implementing a cap on the equity concern in the model and by testing different settings for the transfer price. The result is shown in Figure 5. From that figure, rather than a reasonable trade-off, a regulatory trilemma results. The results shown in Table 5 are indicated in Figure 5 as points of reference.

[11] On the other hand, without this simplification the cost recovery issue could be even worse as the highest consumption brackets (and thus rates) would be avoided.

Figure 5: The trilemma between equity concerns and the cost recovery of the Single Buyer Entity and DISCO



What is most surprising about Figure 5 is the steep increase in the cost recovery issue for the DISCO when slightly reducing the equity concern. Two characteristics of the African energy market would accelerate the utility death spiral, compared to parallel cases in European, North America, and Australia. First, note that as shown in Table 2, each consumer in the highest consumer class is cross-subsidizing consumers in the lowest consumer class. As consumers in the high consumer class load defect from the grid, the financial deficit (in EGP) increases at a much higher pace than the decrease in the total volume of sales (in MWh). Second, by capping the equity concern at, say, 10% under a scenario with no cost recovery issue for the Single Buyer Entity, a cost recovery issue of 195% for the DISCO results. Counterintuitively, the DISCO is not only subject to a pure loss of 100% of its investment. It also incurs an additional loss of 95%. To understand this number, it should be remembered that DISCO does not only need to receive income to recover its sunk investments in networks. It also needs to receive income to satisfy its supply obligations for which the DISCO pays the transfer price. These supply obligations put additional financial pressure on the DISCO compared to the unbundled DSOs found for example, in Europe. Therefore, a complete load defection scenario cannot, by definition, result in a financial deficit of more than 100% in the unbundled model, while this, in theory, can happen in the Single Buyer Model.

5.1.3 Discussion and main findings for the IBT design

We can confirm that in a high-cost BTM technology scenario, there are limited regulatory concerns. This result confirms why an IBT methodology has been favoured in Africa and, indeed, all over the world in the recent past (Lin and Jiang, 2012; Alleyne and Hussain, 2013). However, the results for the future low cost BTM technology scenario are drastically different. Even though stylized, these results confirm that a reasonable end-user rate design is conditional upon BTM technology costs; an IBT design works well when consumers' elasticity is limited, but it fails when an alternative to passively consuming electricity from the grid becomes affordable. In fact, under the assumptions used in this paper, IBT design will push consumers towards load defection jeopardizing the recovery of the regulated costs. Even if no such drastic load defection occurs, the intuition remains the same, the IBT design quickly becomes unsustainable in a low-cost BTM technology scenario.

More precisely, under the currently in place volumetric IBT design and low cost BTM technology, we cannot avoid the regulatory trilemma described above. The challenge with IBT is that it depends on the wealthier consumers for recovering the DISCO's costs. At the same time, those consumers will be the first to load defect by installing solar PV as their business case is most profitable due to the high volumetric rates they are subject to. With full cost recovery of the regulated entities being a regulatory objective for transitioning African utilities or for those struggling to afford access to electricity, this kind of (accelerated) death spiral cannot be tolerated. [12]

Frequent rate revisions are slow and subject to opposition. However, we observe that should end-user rates not be quickly increased to avoid cost recovery issues, the investor-owned DISCO gets 'financially sandwiched' between the regulated end-user rate and the regulated transfer price. This situation recalls, to some extent, the 2000-2001 California crisis. In that case, the 'threat' came from upstream instead of downstream consumers. The investor-owned US distribution utilities were sandwiched between increasing upstream sourcing prices and a capped downstream end-user rate. Bushnell (2004) describes how the capped retail rate exacerbated the challenge as it did not signal increasing upstream prices to consumers. It led, instead, to inelastic demand that further increased wholesale prices. Borenstein (2008) explains that after the crisis, a bolder IBT design was adopted by shifting from a two-tiered into a five-tier IBT. This kind of redesign was successful in avoiding equity concerns while ensuring utility cost recovery. A key assumption was that demand is inelastic, i.e. there was the idea that consumers do not react to price signals including those in the highest blocks.[13] This assumption was valid at that time. However, it is no longer valid. Therefore, regulators will, as we see in the next subsection, have to resort to alternative designs.

5.2 Differentiated Fixed Charge (DFC) design

In this subsection, we first introduce the proposed alternative end-user rate design. After that, we discuss the results under the high-cost and low-cost BTM technology scenario. Finally, we discuss implementation issues with the alternative proposal and provide practical recommendations on how to overcome these issues.

5.2.1 The rationale and implementation of the DFC design

In economic theory it is well known that volumetric end-user charges should be set at the marginal cost of electricity production, while residual costs should be recuperated through fixed charges (Burger et al., 2020; Joskow et al., 1989). Ideally, the volumetric charge should only reflect the utility's avoided cost, that is a system of spot pricing representing the value of electricity with its spatial and temporal granularity (Joskow et al., 1989; Schweppe et al., 1988). However, due to a lack of precise information, the marginal cost is proxied by the average variable generation cost. We propose to set the volumetric end-user rate equal to this weighted average variable generation cost. In this subsection, we keep the cost-reflective transfer price function as described in Eq. 23 and 24. This means that the volumetric end-user charge equals the volumetric transfer price as shown in Eq. 25. As such it is not only the Single Buyer Entity but also the DISCO that hedged for changes in the volume of electricity sales. Please note that the volumetric end-user charge is the same for all consumer classes.

$$R_{v,i} = \mathrm{WGC} = \mathrm{TP_v} \quad \forall i \tag{25}$$

The significant remainder of costs, being the DISCO's sunk network costs and the sunk costs of the Single Buyer Entity, are allocated via a fixed charge (in EGP per connection).[14] However, implementing

[12] Full cost recovery of utilities is highly stressed for electricity industries transitioning from an integrated utility environment to a competitive wholesale/retail market environment as suggested by Rudnick and Velasquez (2018) and Besant-Jones (2006).

[13] As reported by Borenstein (2008), the implementation of the five-tier increasing block tariff caused the highest block to range from about 80% higher to more than triple the price on the lowest block in 2007.

[14] More complex tariff design could include an additional peak coincident charge to signal future grid costs as, for example, explained by MIT Energy Initiative (2016). However, the implementation of a measured capacity-based charge would rely

relatively high uniform fixed end-user charges that are equal for all consumers is often challenged by equity concerns. It is argued that if a uniform fixed charge largely replaces the volumetric charges, costs would be shifted from richer high consumption consumers to poorer lower consumption consumers. Kolokathis et al. (2018) analyse German electricity demand data and show that, by introducing a high uniform fixed network charge, low consumption consumers can pay up to two and a half times as much per unit of electricity compared to high consumption users. Schittekatte and Meeus (2020) explain how increases in fixed charges are often rejected or capped in many jurisdictions to combat this kind of inequity. The implementation of uniform fixed charge would be even more challenging in an African context. Remember that with increasing block tariffs low income consumers not only typically consume less but also pay less per kWh consumed.

Therefore, inspired by Battle et al. (2020) and their Spanish case study, Burger et al. (2020) and their Chicago case study, and Borenstein (2020)'s Californian proposal, we propose to introduce Differentiated Fixed Charges (DFC), per metering point, to allocate the sunk costs to the end-users. The idea is that the fixed charge is differentiated per consumer group based on an adequate hard-to-game metric. In this paper, we propose to differentiate the fixed charge based on historical consumption levels. Namely, the magnitude of the fixed charge per consumer is differentiated based on the consumer class a consumer belonged to under the IBT design, which is in itself based on (historical) consumption levels. By allocating sunk costs according to this kind of metric instead of current usage, distortions and costs shifts between consumers are avoided.

The monthly DFC in the base case scenario (without BTM technology adoption) is computed as shown in Eq. 26. By designing the DFC in this way, the consumers belonging to the different consumer classes do not see a change in their total electricity bill compared to the IBT design in the base case scenario.

$$R_{f,i} = \frac{\mathrm{AUB}_{\mathrm{i,IBT}} - \mathrm{M} * \mathrm{W} * \mathrm{R}_{\mathrm{v}} * \sum_{\mathrm{t}} \mathrm{GW}_{\mathrm{t,i}}}{\mathrm{M}} \quad \forall i \tag{26}$$

5.2.2 Results DFC under both cost scenarios

As shown in Table 6, the proposed DFC methodology manages in overcoming the regulatory concerns in both the high and low-cost BTM technology scenarios. We discuss first the results in the high cost BTM technology and afterwards in the low-cost BTM technology scenario.

on currently unavailable smart metering, smart grid infrastructure and advanced network cost models. See, for instance, Meeus et al. (2020).

Table 6: Results with the differentiated fixed charges under the two BTM technology cost scenarios

Parameter / Variable / Regulatory Metric		High Cost	Low Cost
Volumetric Rate Component (EGP/kWh)	High-consumption	0.714	0.714
	Medium-consumption	0.714	0.714
	Low-consumption	0.714	0.714
Fixed-Rate Component (EGP/Month)	High-consumption	812.8	812.8
	Medium-consumption	272.8	272.8
	Low-consumption	0.8	0.8
Transfer Price Components	Volumetric (EGP/kWh)	0.714	
	Fixed (M EGP/Month)	3.473	
PV adoption per consumer high-consumption (kW)		0	6.7
Battery adoption per consumer high-consumption (kWh)		0	0
PV adoption per active consumer medium-consumption (kW)		0	3.5
Battery adoption per active consumer medium-consumption (kWh)		0	0
Efficiency Concerns (%)		0%	-6.2%
Equity Concerns (%)		0%	0%
Cost Recovery Concerns of DISCO (%)		0%	0%
Cost Recovery Concerns of Single Buyer (%)		0%	0%

High-cost BTM technology scenario

Under the DFC design in the high-cost BTM technology scenario, there is no investment in solar PV or batteries. The volumetric charge equals the weighted average generation costs, instead of being inflated for the high-consumption class to cross-subsidize the low-consumption class. As a result there is no over-incentive to invest in solar PV. As such, the DFC design not only performs better in terms of equity and cost recovery compared to the IBT design in this BTM technology cost scenario. It also performs better in terms of cost efficiency.[15] The Single Buyer Entity's cost recovery issues are avoided by directly implementing the transfer price function as shown in Eq. 23 and 24.

Low- cost BTM technology scenario

In the low-cost BTM technology scenario, the DFC design shows robustness across all regulatory metrics. The efficiency metric shows the same value as under the IBT design and the low-cost BTM technology scenario (Table 4 and 5) as the same amount of solar PV is installed. The levelized cost of solar PV is lower than the weighted average generation cost in this scenario and consumers invest in as much solar capacity as needed to bring their annual net consumption to zero. However, due to the DFC design, the distributional impact and cost recovery issues for the regulated entities are neutralized. In short, by replacing the IBT with the DFC design, the regulatory trilemma as discussed in Section 5.1.2 can be avoided. However, the DFC design also presents challenges that have to be considered. We discuss these in the next subsection.

[15] If additional incentives to invest in solar PV are deemed appropriate, these can always be given via direct subsidies instead of implicitly via the electricity bill. By doing so, no or at least fewer distortions are created.

5.2.3 Implementation issues DFC design and practical recommendations for overcoming difficulties

We find three important implementation issues with the DFC design. First, the determination of the proxy to base the differentiation upon. Second, the risk of inefficient grid defection. Third, the adverse effect the DFC design could have on energy efficiency.

Regarding the first implementation issue, this question has been discussed and studied in depth by Battle et al. (2020), Burger et al. (2020), and Borenstein (2020). Batlle et al. (2020) introduce the principle of 'backward cost causation'. In other words, when sunk costs were incurred, they certainly had a cost driver. Therefore, historical data for that cost driver can be used to differentiate the fixed charge. Examples are peak demand, contracted capacity, or consumption volumes. In Africa, due to a lack of data, it is most practical to differentiate the fixed charge based on historical consumption levels. Under the IBT design, the (volumetric) charges were already differentiated per consumption band. The practice of charging different rates to different groups of consumers, as introduced in Table 2, might therefore be more easily acceptable in an African context. However, there are differences, namely that: under the DFC design there are differentiated fixed and undifferentiated volumetric rates per consumer class; and under the DFC design the division into different consumer classes is based on historical and not current consumption data. Importantly, historical (averaged) consumption data for a sufficiently long period should be used to avoid current consumption decisions alter the consumer class to which a consumer belongs. A period of ten to twenty years can be argued for, given that infrastructure might need to be redeveloped, and as such, the backward cost causality principle is diluted. [16] This is especially true in a fast-developing context such as is found in early twenty-first century Africa.

There are other proxies to base the differentiation of the fixed charge upon. Burger et al. (2020) test a differentiation based on geography or customer income. The option of introducing opt-in low-income programs to mitigate the impact of increased fixed charges is also contemplated. Even though not free from flaws, the authors argue that having differentiated fixed charges, whether based on historical consumption, geography or income is better than low-income programs because such programs historically have very low opt-in rates due to uninformed consumers. Finally, Borenstein (2020) advocates for an income-based fixed charge. More precisely, he proposes that consumers pay a substantial uniform monthly fixed charge. But, on their state tax return consumers would have to document these payments by submitting a utility ID that would be matched with the billing information from their utility. This process would then automatically trigger a refund of all or part of their fixed charge payments depending on the income of this or that consumer. In the last step, the state would then collect the rebated revenue from the utility.

The second implementation issue is the risk for inefficient grid defection. In the IBT design load defection was incentivised, which led to a violation of regulatory principles. The same problem could emerge due to grid defection under the DFC design. If the differentiated fixed charges for the high consumption class reached a level where it makes more economic sense for these consumers to go off-grid by installing solar PV and batteries than to remain connected, grid defection would occur. Grid defection would, in most cases, be inefficient as the infrastructure to provide electricity for these consumers has already been built. The sunk costs cannot be billed to grid defected consumers anymore and would have to be allocated to other consumers. These other consumers would see their fixed charge rise and as such their incentive to go off-grid increases. Again, a utility death spiral would be set in course. We re-ran the model under the same parameters as in the low-cost BTM technology scenario of Section 5.2.2. with the only one difference. We lowered the battery costs until grid defection occurs. Grid defection occurs in our stylized example with battery costs at 77$/kWh or lower. At that point, it is cheaper for consumers from the high consumption consumer class to install a battery of 20kWh and

[16] The authors acknowledge the fact that differentiating the fixed charge between housing units would impact the value of the unit itself on the real estate market. However, it is believed that this kind of impact is acceptable and that it can be integrated and easily handled as the real estate market has experience with such costs (e.g. energy efficiency labels of a property or condominium fees for a flat).

13.5kWp PV than to remain grid-connected. As the high consumption consumers defect from the grid, efficiency gains are decreased (from -6.2% to -0.7%) and equity concerns are raised (from 0% to 10.1%), when compared to the results in Table 6. The rise in the fixed charge of the active consumers in the medium consumption class is not, in this scenario, high enough to incentivise these consumers to grid defect and to further worsen the outcome of the regulatory metrics.

However, we believe that the violation of regulatory principles due to grid defection under the DFC design can be more easily addressed than the issues resulting from load defection under the IBT design. First of all, it is a lot harder to grid defect than to load defect. Keeping the same comfort level, in terms of reliability, is more challenging off than on the grid. As briefly alluded to in the data section, by using a simple load and PV profile we can only indicate the order of magnitude under which we can see grid defection happening in our case study. In reality, more elaborate engineering models considering varying weather and electricity consumption profiles need to be deployed to dimension the batteries and solar PV in detail. Examples can be found in the papers by Hittinger and Siddiqui (2017) and Gorman et al. (2020). One proposal to avoid inefficient grid defection would be to implement exit fees as discussed by Gorman et al. (2020). The exit fee would be computed at a level to force disconnecting consumers to pay their share of sunk costs that were incurred on their behalf. A challenge with this approach would be determining the correct (and legal) level of the exit fee. We advise regulators to deploy models such as those introduced in Hittinger and Siddiqui (2017) and Gorman et al. (2020) to back-test whether the foreseen levels of the differentiated fixed charges would incentivise (often inefficient) grid defection. Were this issue to be relevant then it would make sense to calibrate appropriate exit fees. Finally, the last resort solution, as also discussed in the Utilities of the future report by the MIT Energy Initiative (2016) is to allow for the under-recovery of the regulated costs as full cost recovery leads to inefficiencies. Unrecovered residual costs would have to be recuperated through other means than the electricity bill. An alternative might be to let taxpayers pay for these costs, as is done with roads in some countries. However, this seems an inappropriate solution for emerging economies where public budgets are already under stress.

Third, with the DFC design, the variable cost to consume electricity decreases quite significantly for the high and medium consumer class, compared to the baseline scenario under IBT. This kind of reduction could lead to increased electricity consumption. In theory, this is not an issue as the volumetric end-user charge is set equal to the proxied marginal cost of generation. However, in reality, not all externalities are included in the marginal cost of generation, most importantly the cost of emissions. If this was, indeed, the case then it would make sense to increase the volumetric charge to include an estimate of this cost and to slightly decrease the differentiated fixed charge accordingly. Borenstein and Bushnell (2018) analyse the current tariffs and carbon prices for all US states. They found that for some states the overly volumetrically charged residual costs make up for the “too low” electricity price in reflecting the average social marginal cost per kWh i.e. one including all other externalities such as emissions. However, this does not always hold. For other states, the final per kWh charge (summing up all volumetric charges, for the network or taxes and levies, plus the energy price) in the bill is either “too high” (e.g., California) or “too low” (e.g., North Dakota) when compared to the average social marginal cost per kWh.

5. Conclusions and policy recommendations

This paper seeks to understand the regulatory implications of increasing penetration of Behind-the-Meter (BTM) technologies and the existing end-user rate design in an African context. The implemented modelling approach captures consumers’ changing preferences driven by both the price development of different BTM technologies and the end-user rate design. The typical African regulatory model is explained, and an Egyptian case study was carried out. We ran the Egyptian model considering the current volumetric Increasing Block Tariff (IBT) design with a minor fixed charge and the proposed alternative, consisting of a Differentiated Fixed Charge (DFC) and a volumetric charge equalizing the weighted average cost of generation. We computed the results under two BTM technology cost scenarios for robustness. The results are presented by discussing the following three metrics proxying regulatory objectives: cost efficiency, equity, and cost recovery of the regulated entities. The two research questions we want to answer are:

- What are the regulatory implications of the increased adoption of BTM technologies under the current end-user rate design?
- Can we mitigate possible concerns through an improved end-user rate design? Or are wider reforms deemed necessary?

Regarding the first question, the results confirm and illustrate the regulatory favourability of the status quo IBT design under high-cost BTM technology. The IBT design manages to ensure the cost recovery of the regulated investments while being perceived as being equitable. However, under a future scenario with lower BTM technology prices, the IBT design is shown to rapidly become unsustainable. We rapidly end up in a regulatory trilemma where the regulated investor-owned DISCO or the regulated Single Buyer Entity would not manage to recover their costs; or in which vulnerable consumers would see a significant increase in their bills.

Two special characteristics of the African energy market would accelerate any utility death spiral for the DISCO, compared to its counterpart in the European, North American, and Australian cases. First, currently, under the IBT design, consumers in the highest consumption segment, paying the highest charge per kWh consumed, are relied upon to recover the DISCO's costs. As the consumers in the high consumer class are the first to load defect from the grid, the financial deficit increases at a much higher pace than the total volume of sales. Second, DISCOs need to recuperate not only the sunk network investments but also their supplied energy costs. DISCOs pay the regulated transfer price to the Single Buyer Entity to fulfil these supply obligations, which put additional financial pressure on the DISCO compared to the unbundled DSOs in most of the Western world. Counterintuitively, a load defection scenario can result in a financial deficit of more than 100% for the DISCO in the Single Buyer Model, while this cannot happen in an unbundled setting. As frequent rate revisions are slow and subject to opposition, the investor-owned DISCO quickly gets "financially sandwiched" between the regulated end-user rate downstream and the regulated transfer price upstream. With full cost recovery of the regulated entities being a regulatory objective in Africa's transitioning utilities or in those struggling to afford access to electricity, an accelerated death spiral would be especially disruptive.

Regarding the second question, we propose to redesign the end-user tariff design to combine a volumetric charge that is equal to the weighted average cost of generation and a Differentiated Fixed Charge (DFC) to recover residual costs. We propose to differentiate the fixed charge based on historical consumption levels to avoid distortions while maintaining existing equity considerations. The magnitude of the fixed charge per consumer is, as such, differentiated based on the consumer class that a consumer belonged to under the IBT design. Under the present IBT design, already the (volumetric) charges have been differentiated per consumption band. The practice of charging different rates to different groups of consumers might, therefore, be more easily acceptable in an African context. However, under DFC there are differentiated fixed and undifferentiated volumetric rates per consumer class and the division in different consumer classes is based on historical and not current consumption data. We discussed three implementation issues with the DFC design, and provided recommendations on how to overcome these challenges. The challenges were: the selection of the proxy used to differentiate the fixed charge upon; inefficient grid defection; and energy efficiency concerns.

The case study also showed that merely revising the end-user rate design is not enough. Wider reforms are needed. More specifically, the efficient functioning of the alternative DFC design is conditional upon a revised regulated transfer price. It was found that because the current design of the transfer price does not well reflect the Single Buyer Entity's cost structure, not only the cost recovery of the DISCO, but also the cost recovery of the Single Buyer Entity would be challenged with the increased adoption of BTM technologies. In that respect, we propose the volumetric transfer price to be equal to the weighted average cost of generation and to recover the remaining costs via a fixed transfer charge. Under the DFC end-user design and the revised transfer price, both the Single Buyer Entity and the DISCO are hedged for changes in the volume of electricity sales. This finding implies that BTM technologies, competing with centralised generation, add to the need for the efficient utility generation cost signalling and as such provide an additional argument for the establishment of a well-functioning electricity wholesale market in the medium or long term.

In terms of applicability, the proposed solutions do not require changes in the existing metering infrastructure, which is typically incapable of reflecting the temporal granularity of electricity. Besides, proposed differentiated fixed charges can be easily integrated in the real estate market. In this paper, we, crucially, modelled an extreme with all sunk costs allocated via the differentiated fixed charge. Such a radical shift in end-user rate design would not be acceptable. Another important regulatory principle here is graduality. What we propose is that regulators and policymakers start moving gradually today towards the proposed rate design and revised transfer price formula to ensure the better integration of BTM technologies tomorrow.

Future studies might usefully investigate the regulatory performance of more elaborated end-user rate design such as capacity-based charges which are conditional upon smart meter technology. In addition, the regulatory performance of an end-user rate design can be assessed under a variety of DISCO circumstances in terms of electrification rates and targets. More detailed data regarding consumer load profiles, solar irradiance profiles, and battery specificities might shed further light on the economics of grid defection. Furthermore, the regulatory impact of the increasing elasticity of not only individual consumers but also groups of consumers, thanks to microgrid technologies, should be scrutinized. Regulatory recommendations are needed to advise on the efficient integration of these new technologies in Africa.

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Annex

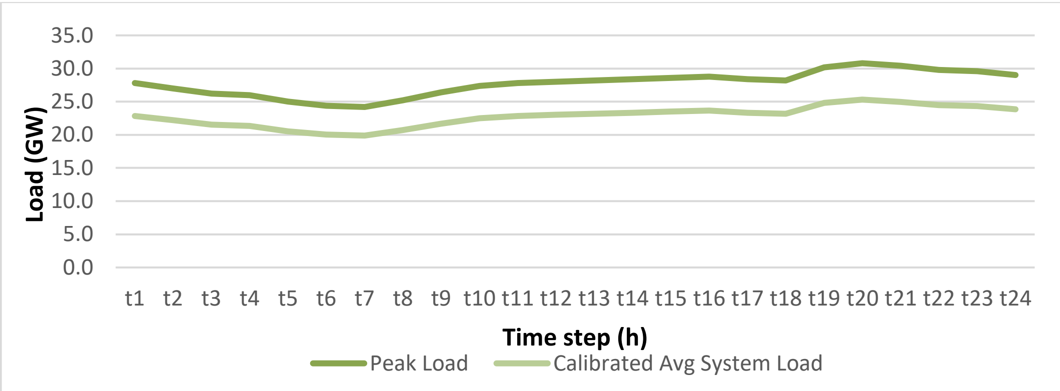
Annex 1: Typical DISCO load curve

The load profile of the DISCO is obtained through two stages. The first starts with obtaining the system load profile while the second calibrates it to the DISCO according to DISCO annual energy sales.

The first stage is to obtain the typical system profile which is an average daily profile derived from the latest annual report of the incumbent utility (EEHC, 2020). Given that the load profile presented in the annual report of EEHC is the profile of the peak day of the year, it can be calibrated against the average daily consumption of a typical day. This average daily consumption is obtained by averaging the annual consumption, which is obtained from the same report. Figure 6 shows both the published peak-day load profile and the derived average-day load profile.

In the second stage, the average daily aggregate load profile of a DISCO is derived from the typical system profile, knowing the ratio of its annual total energy sales to that of the whole system. A look at the annual energy sales forecast of DISCOs suggests that there is a wide range of energy volumes (EgyptERA, 2020c). Among the varying sizes of licensed DISCO, we assume a representative energy sales forecast of DISCOs of around 90 GWh. With this level of annual energy sales, the DISCO load profile is derived, as shown in Figure 3 in the body of the text.

Figure 6: Published Peak-Day vs Derived Average-Day Load Profile of the Incumbent



Annex 2: Different consumer segments in Egypt

Table 7 shows the different volumetric end-user rates corresponding to different consumption levels, along with the fixed component of the rate (EgyptERA, 2020b). The implemented volumetric-based IBT rate design categorises consumption into three main consumption bands. Due to the implementation of these bands, consumers in the same band can end up paying different average rates. As an example, two consumers are considered in the second one with a consumption of 400 and 500 kWh per month. Both pay the first 200 kWh at a volumetric rate of 0.97 EGP and the next 150 kWh at a volumetric rate of 1.23 EGP. Afterward, a volumetric rate of 1.36 EGP will be levied on the remaining consumption of both consumers; only 50 kWh for the first while 150 kWh for the other one. This means that consumers in the same band with different consumption levels would pay different average rates. Additionally, these rates is quite progressive, for example if the consumption increase from 500 to 700 kWh per month, then the whole consumption is billed at 1.36 EGP and not merely the amount above 351 kWh.

Table 7: Tariff blocks and corresponding consumption 2024/2025

Tariff Band	Consumption Span (kWh / Month)	Volumetric Component (EGP/kWh)	Fixed Component (EGP/Consumer) per Month
First Band	0 – 50	0.71	1
	51 – 100		2
Second Band	0 – 200	0.97	6
	201 – 350	1.23	11
	351 – 650	1.36	15
Third Band	0 – 1000		25
	0 – above 1000	1.45	40

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