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THE DISTRIBUTED ELECTRICITY GENERATION DIFFUSION IMPACT ON THE BRAZILIAN DISTRIBUTION UTILITIES

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ABSTRACT

Over the last few years the electric sectors worldwide have been the scenario of several technological changes, with the growing share of variable renewable energy generation sources (mostly wind and solar photovoltaic) acting as the most striking feature. A large portion of this installed capacity being added through distributed generation (DG), mostly by rooftop generators. This movement is challenging the traditional operation of the Brazilian electric sector, which was built for more than a century over principles of top-down centralized generation and mostly controllable energy sources, usually far off from the consumption centers, and is acting as a disruptive force. By the current regulation, a significant diffusion of DG during the period between rate recalibrations (usually done after every four years) might imply in large losses to the distribution utilities in face of a significant uncertainty concerning the diffusion rate. This paper analyzes the role of the Brazzilian rate structure for electricity in this scenario of DG diffusion. It is found that the current rate strutcture is inadequate for dealing with such diffusion, creating cross subsidies and threating the important economic equilibrium of the services of distribution.

INTRODUCTION

Over the last few years the electric sectors worldwide have been the scenario of several technological changes, with the growing share of variable renewable energy generation sources (mostly wind and solar photovoltaic) acting as the most striking feature. Initially, the wind generation led this movement, with its expansion determining the growth dynamics of renewable energy. However, lately, solar photovoltaic (solar PV) generation has begun a movement of strong growth as well, mainly after 2010 (REN 21, 2014). A characteristic of this PV movement is its diffusive expansion pattern, with a large portion of its installed capacity being added through distributed generation (DG), mostly by rooftop generators (IRENA, 2016).

Even though in several countries around the world the distributed generation has already reached significant participation in the overall installed capacity, in Brazil its diffusion is a recent phenomenon. The country's regulatory guidelines concerning distributed microgeneration were first published in 2012, via the publication of ANEEL's (Brazilian regulator) Normative Resolution 482 (ANEEL, 2012). It defined what constitutes microgeneration, making it legal and the net metering as the incentive scheme. As March 2016, more than 8.934 microgeneration connections to the grid were already performed, with more than 8.835 being solar PV, representing approximately 68 MW of installed capacity (ANEEL, 2016 a). The maintenance of such incentive and the expected technological cost reduction will result in an increasing number of consumers adopting the PV DG. EPE (Energy Research Company of Brazillian government) projects that in 2030 they might reach up to 8,2 GW, generating up to 1,4 % of total consumption in the same year (EPE, 2016).

This movement is challenging the traditional operation of the Brazilian electric sector, which was built for more than a century over principles of top-down centralized generation and mostly controllable energy sources, usually far off from the consumption centers, and is acting as a disruptive force (Castro, 1985; Barros, 2014). One of the main concerns is the pressure over the distribution utilities business model. In its historical framework, its business model was characterized by an ever growing base of customers and energy demand, providing their capital investments a lower risk and stability to their business model.

By the current regulation, a significant diffusion of DG during the period between rate recalibrations (usually done after every four years) might imply in large losses to the distribution utilities in face of a significant uncertainty concerning the diffusion rate. The reduction of the customers' base with the adoption of the PV technology for self generation not only is an uncertainty factor, but is also a distortive one, by the Brazilliaan current regulatory practice. The required revenue that allows the utilities business to operate with an adequate profit rate is achieved through the electricity rate payment by the customers. Its costs are paid by them in proportion to their consumption, including the fixed costs. Since the distribution utility remains indispensable even for the PV self generation adopters, it should be the case that these adopters remain contributing with the fixed costs. But that is not the case. When they significantly reduce their net consumption, they end up paying for a little fraction of the costs (by the volumetric mechanism), which are paid by the other customers, creating a cross subsidy.

Considering not only the period between rate calibrations, but also the long run, after every calibration, since the customers' base is smaller, the electricity rate has to increase, which translates itself into higher incentives for PV self generation adoption, possibly creating a self powered cycle, also known in the literature as the Death Spiral.

BRAZILLIAN DISTRIBUTION UTILITIES RATE DESIGN

In Brazil, the distribution utilities perform a regulated economic activity. They are responsible for the electricity supply, by carrying capital investments in electric infrastructure (which consists of poles, wires, converters, adapters and so on) and by acquisition and resale of energy (service for which there is no profit, but only costs onlending). The revenue for their services is regulated, being composed by a sum of operational costs, and a fair return on capital (calculated by WACC criteria, considering the sum of all their capital expenditure). The sum of the two components is called Required Revenue. This Required Revenue will be meet through the rate payment by the aggregation of consumers. In order to set the respective rate that will allow the equivalence between the actual revenue and the Required Revenue in any period, the energy consumption has to be projected to the upcoming years. The setting up (or calibration) of the rate level is made, usually, after every four years, and considers the projected consumption for the period (ANEEL, 2016 b).

Electricity consumers connected to the distribution utilities grid are classified according to three major categories: commercial, industrial and residencial. For each one of these categories, there are different rate designs, aiming to adapt to their respective characteristics. High and medium voltage, usually industrial consumers, are charged via binomial rates, with a demand component and a consumption component. For low voltage consumers (all residencial and most of the commercial consumers), there is not a demand component, and their energy consumption and grid's usage is charged according to their consumption alone, and in this case, the rate is said monomial (Fugimoto, 2010).

The consumers' charged rates aims to remunerate the energy generators and the distribution and transmission utilities. When a binomial rate is applied, then the aggregation of the demand component of all the consumers must remunerate the distribution and transmission utilities, leaving the consumption component to remunerate the energy generation utilities. In this case, it can be said that the rate is cost reflective (Analla & Honakpuro, 2016). However, when a monomial rate is charged, distribution and transmission services are also remunerated by the consumption level of each consumer and this lump-sum criteria is denominated "volumetric" (Fugimoto, 2010).

POTENTIAL ACCUMULATED LOSSES FOR THE DISTRIBUTION UTILITIES WITH THE DG DIFFUSION

The diffusion of DG impacts directly an important uncertainty factor: the consumption projection. In a scenario where a random number of consumers adopts PV microgeneration, uncertainty exerts pressure over consumption projections, given the multiple variables involved. In every four-years period, during which the rate is no calibrated, a number of utilities' consumers will adopt self PV generation, leading to a reduction of the current demand. Demand projections are usually conservative, showing traction to close previous years. When the energy demand is in a steady growth trajectory, like during most of the time in the last century (even in the presence of GDP drops, the vast majority of four-years sequences show a increment in energy consumption), a higher than estimated consumption implicates in a higher actual revenue than its Required Revenue counterpart. This gain, achieved from the difference between the two, is usually spent in acquisition of a higher cost energy in the spot market, for correcting the demand estimates. But when consumption behaves and evolves in an erratic and descending pattern, like in the presence of DG diffusion, these conservative estimation may lead to a scenario of periodic losses to the utilities.

The Figure 1 presented bellow illustrates an hipotetic scenario where there is a steady adoption of DG by consumers. In the Figure 1, the blue line represents the monthly Required Revenue (1/48 of the estimated for the four years). However, since there is a steady and unforeseen adoption of PV microgeneration by a certain share of the consumers, the Required Revenue is not achieved, and the actual revenue is increasingly lower that the former. Since the difference between the two represents a loss of revenue, the gray triangular area forms the accumulated losses of the four years period in between rates calibration.

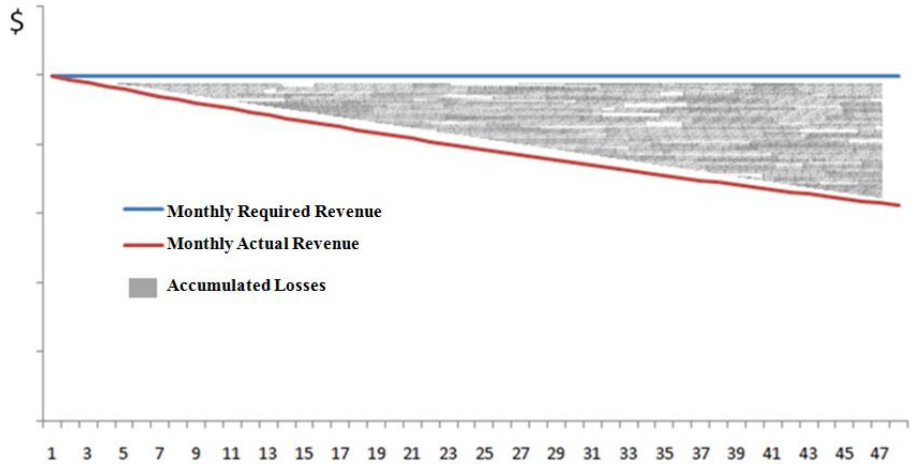

Figure 1: In Between Rate Level Calibration Dinamics of Actual and Required Revenues (Own Elaboration)

Since the above shown case is expected to be the norm in the upcoming years, there is a need for a mechanism that corrects the accumulated losses issue. One of these mechanism is the decoupling. It allows the remuneration of the distribution services in accordance with the aimed return on CAPEX, in despite of imbalances between the projected and actual demand volumes (Mozkovitz et. al.1992). Decoupling works with "balancing accounts", which are responsible for registering differences between actual and required revenues, conducing regulator to counter balance the results of the last perior in the subsequent one. This mechanisms provides more freedom to rate setting, since mistakes are corrected on subsequent periods, allowing a less conservative approach to demand projection (or in DG diffusion), reducing impacts over the cashflows of the utilities.

Nonetheless, while decoupling is an important regulatory mechanism to mitigate accumulated losses and cashflow issues, it might create perverse incentives for the distribution utilities. A very important and perverse incentive created is the Averch-Johnson effect. This effect is the incentive that regulated utilities possess to over-invest in CAPEX, replacing, when possible, investments in OPEX with investment in CAPEX. These investments replacements are usually inefficient ones, acting outside an efficient labor-capital substitution schedule.

As observed by Steve Kihm (2009), since the utilities remuneration is a fixed rate of return over the capital investments (in electric materials that allows physical distribution of electricity), with OPEX having their costs only covered, inaccuracies in the fixed rate of return lead to a over-investment in CAPEX. The rate of return is fixed with the calculation of the WACC (wheighted average cost of capital). However, this is not an infallible methodology, and there is an intrinsic and significant degree of arbritrariness in the calcultation. The only party that truly knows with a degree of relative certainty its actual cost of capital is the utility. Since it would not offer its services in case of a lower rate of return than its capital cost, the case is that it is higher than, or, at least, equal to it. Common sense shows the improbability of the equality scenario, and so, scenarios with a fixed rate of return higher than the capital costs, which will induce over-investment and incefficient replacement of OPEX, are the norm. Since decoupling allows the rate of return remuneration to be achieved in despite of demand imbalances, is strenghtens this incentive.

This dynamic can be directly observed from the stock price of a publicly held company, with the use of Gordon's Discounted Dividends Model (it can be found in the book *The Cost of Capital to a Public Utility*), as described in Equation 1, below.

$$P = \frac{NBx + (x - c)I}{Nc} \qquad (1)$$

P is the stock price, N is the number of stocks in present shareholders property, B is the book value of the stock, x is the defined rate of return defined by the regulator, c is the actual (true) opportunity cost, and I is the volume of new investments to be financed (CAPEX). Since the objective of the utility is the maximization of its stock price (in many instances, CEOs are incetived to this with the use of options as a share of their remuneration), the objective is to maximize P. With the aid of differencial calculus is possible to determine the effect (Equation 2) of increasing I (CAPEX) in the Equation 1:

$$\frac{\partial P}{\partial I} = \frac{x}{c} - 1 \qquad (2)$$

As shown above, x has to be higher than c ($x \geq c$), in order to a utility offer its services. In the case $x = c$, the WACC was perfectly calculated and there is no perverse incentive to increase CAPEX inefficiently. But, very often the case is that $x > c$, and augments in CAPEX (I) investment will result in augments in the stock prices, resulting in the Averch-Johnson effect.

POTENTIAL DEATH SPIRAL FOR THE DISTRIBUTION UTILITIES WITH THE DG DIFFUSION

Another rising concern related to the diffusion of DG and its implications on the demand of electricity deriving from the distribution utilities is the loss of economic logic and financial sustainability. A direct way of analizing this threat is understanding the costs components of the electric rates. Equation 3 presents them:

$$\text{Rate} = \frac{\text{Fixed Costs} + \text{Variable Costs}}{\text{Total Demand}} = \frac{\text{Fixed Costs}}{\text{Total Demand}} + \frac{\text{Variable Costs}}{\text{Total Demand}} \quad (3)$$

The rate is set in R$/kWh, the fixed and variable costs are set in R$ and the total demand is in kWh. So, it is possible to classify the rate's pertaining costs in fixed and variable ones. The fixed ones does not respond to variations on the total demand volume (except in case of huge increases) and the variable ones do respond. What would happen with the rate level in case of a total demand reduction? If it is considered, for the sake of simplicity (without losing traction with the real world), that the variable costs vary in the exact same intensity as the total demand, then the variable component would remain the same and the rate would not suffer any impact from it. However, the fixed component would certainly increase, sinse the fixed costs remain the same, but its denominator is reducing. The final effect is an increase in the rate level. Since the economical attractivity of a PV system is dependable on the rate level, this rate increase is responsible for a raise in the incentives for the adoption of such systems for self generation. A increase in the share of consumers adopting PV will inevitably lead to a raise of the rate level, since the consumers total demand will fall. This hypothetical cycle is called "The Death Spiral". The Figure 2 below represents the dynamics of the spiral.

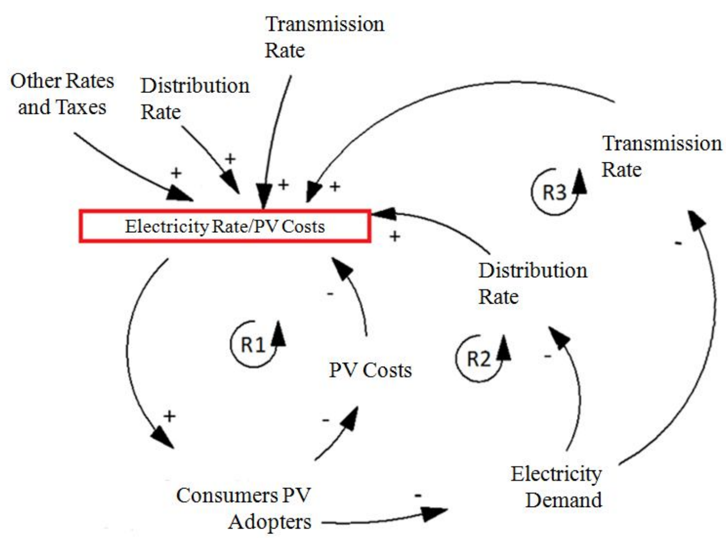

Figure 2: Death Spiral Illustration (Dyner *et al.* 2016)

An important observation, concerning distributional matters, must come to light in face of this rate structure. As seen, reductions in electricity consumption from the distribution networks imply in a reduction of costs from its services for those that adopt PV systems. An obvious reason is the fall in demand, so total costs with the service must fall (costs equal rate multiplied by demand or quantity). However, an addition reduction comes from the reduction from the network costs, even though it remains being used by these consumers. Even more, from a cost reflection point of view, these consumers should keep paying for it, regardless of the adoption of PV systems. Distribution utilities will remain supplying energy in moments of inexistent self generation and will also absorb the energy generated in excess, acting as a battery for the adopters consumers. What is happening in the above exposed rate increase is a *cross subsidy*, with regular consumers paying for a share of the network costs of adopters. This implications will be explored further ahead in this paper.

This hypothetic death spiral may not happen, since several factors must be met in order for it to happen. Even if the installation of a photovoltaic system is economically sound, its purchase may not be feasible without a loan or funding, adding to the costs another variable: the funding costs. The conditions might not be good or even inexistent for some consumer. Uncertainty with the future rate levels and possible changes in regulation (*net metering* might be replaced by another incentive scheme) are strong arguments for high interest rates. Another point that should be considered, is related to the existence of technical barriers. Some building does not have an appropriate area, with good sun exposure or, at least, for a good part of the daylight time. Even though technical barriers can be overcame with the creation of "solar condominiums", as provided by ANEEL's Normative Resolution 482, where consumers can aggregate themselves, pay for the installation in a remote location of a photovoltaic system, and use it as a source of self generation, there are coordination and informational difficulties for the creation of such systems.

From the abovementioned, it is clear that a ratio higher than one for Electricity Rate/PV Costs (ER/PVC) is not enough to star a process of adoption. It is also not enough to keep the spiral working, since other factors, as funding conditions, income level, technical barriers and informational/coordinational difficulties must be considered. All of these factor, aside from de ratio ER/PVC (but considering its level), can be summed up and represented economically in the *price-elasticity of demand*, e_p .

Henderson (1986), found the relationship between the e_p and the costs structure of the monopolist that constitutes a stable and an unstable equilibrium. If the relationship between both the e_p and the costs structure is on of stable equilibrium, raises in the prices (rates) will lead to a lower demand, but will not be strong enough start a cyclical phenomenom. However, if they have a relationship that constitutes an unstable equilibrium, disturbances in the equilibrium, started, for example, by a raise of prices (rates), will lead to a series of demand reductions and prices increases, increasingly stronger, ultimately leading to economic insustentability.

Costello and Hemphil (2014) used the Inequation 4 bellow to represent the case in which such relationship will lead to a stable equilibrium.

$$e_p > \frac{P}{P - mc} \qquad (4)$$

In Inequation 4, e_p represents the *price-elasticity of demand*, P represents the rate level and mc represents the marginal costs. In case of change, with the left side of (4) being lower than the right, the market enters in a unstable equilibrium. Figure 3 below represents both markets condition.

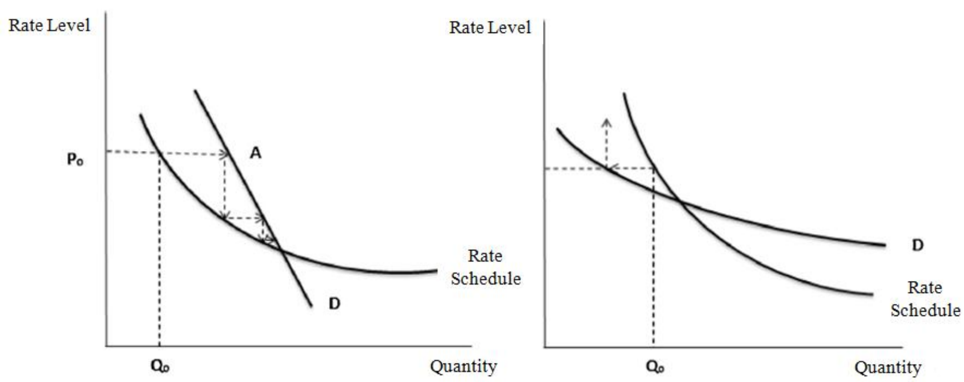

Figure 3: Adapted from Costello e Hemphil (2014)

The graph on the left of Figure 3 represents a stable market, market by the condition of Inequality 4. The rate schedule is the set of points that represent the rate needed to achieve the Required Revenue. Since, by Equation 3, unitary costs rise with a lower total demand, the rate schedule has a negative inclination, just like the market demand, represented by D in both graphs. The elasticity represents the inclination of the demand curve, with higher elasticities present in less steep demand curves. The rate schedule inclination is embodied in the right side of Inequation 4. From this, it is possible to conclude that when the demand curve is more steep than the rate schedule, there is a stable equilibrium. The other case is true if the contrary is observed, as in the right graph of Figure 3. In the last case, if there is a demand reduction, the rate has to raise in a way that is incompatible with the demand, just like in the case of a stable equilibrium, but differently from it, required an even higher rate adjustment, in an increasingly fashion.

Even though there is little controllability over the elasticity conditions (and even if there was, it is questionable acting over it), the rate increasing rhythm might be reduced if the cross subsidy is eliminated or reduced. The existence of the cross subsidy is due to the rate and costs structures. A rate structure with an economical logic of reflective costs should have its network costs divided between consumers in a non-volumetrical criteria. Just like in the high voltage categories, low voltage consumers should be charged by a binomial rate structure, with the networks costs being charged in proportion to electric demand (in watts) or another criteria. Equation 5 below represents the case:

$$\text{Rate} = \frac{\text{Fixed Costs} * (\alpha)}{\text{Other Criteria}} + \frac{\text{Fixed Costs} * (1 - \alpha)}{\text{Total Demand}} + \frac{\text{Variable Costs}}{\text{Total Demand}} \qquad (5)$$

In Equation 5, α (that varies between 0 and 1) represents the non-volumetric network costs (it is being considered that these are the only fixed costs) share in the rate structure, and 1- α the volumetric fixed costs share. The higher α, the lower is the raise in the rate from economical demand (in watts-hour) reduction. Currently, in Brazil, the α is very low for those consumers of low voltage.

CONCLUSIONS AND FURTHER RESEARCH

As observed, the current rate structure and regulation, which is applied to low voltage consumers, is inadequate to a scenario of significant distributed PV diffusion. The dependence between sales of energy volume and remuneration of the utilities services, without considerations to corrections in case of deviations is not well fit to a scenario of uncertainty on demand levels, like in the case of distributed PV diffusion.Also, the rate's volumetric characteristic allows the appearance of a cross subsidy, from consumers that remain fully dependent on the distribution network to those that adopt a PV system. Not only this subsidy this subsidy created disturbances of costs distribution between consumers, it also threatens the economic equilibrium of the distribution services market, with the potencial death spiral effect.

Research must be conducted, aiming to change the volumetric character, substituting it for another criteria for network costs remuneration. Even though it might be expensive to measure electric demand (in watts) for low voltage consumers, since it required technical investments, estimations of its costs and benefits should be tried. The same is applicable for a flat fixed tariff for connection to the distribution grid. In the last case, income characteristics of the different consumers must be taken in consideration.

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