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Status, Challenges and Options for the Future

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Abstract[*]

This paper provides a general characterization of overall power regulation and a detailed characterization of the ongoing evolution of distributed rooftop photovoltaic (PV) regulation in Costa Rica. The paper further develops rooftop PV adoption models for several classes of consumers and evaluates maximum adoption rates under current regulations and alternative regulations, evaluating the impact on the cash flow of distribution utilities under each scenario. The paper subsequently assesses the institutional architecture of power regulation in Costa Rica and contrasts it with international best practices / regulatory consensus. Finally, the paper offers policy recommendations that might help Costa Rica achieve a better balance between conflicting regulatory goals through changes in regulatory rules and institutions.

JEL classifications: K23, K32, L94, L98
Keywords: Power regulation, Electricity, Solar energy

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1. Introduction

1.1 Why Costa Rica?

Solar and wind power generation are making important inroads in several Latin American countries, whether in the form of utility-scale wind farms, as in Uruguay, or distributed solar, as in Costa Rica. The introduction of these new power sources brings along potentially massive fluctuations in power generation, and in the case of distributed generation, potentially two-way flows of energy.

These new developments will demand upgrades in the electricity grid, while regulatory norms and institutions—designed for an era of centralized and vertically integrated utilities working under monopoly conditions—will have to be adjusted to deal with the vertical unbundling of energy markets, the decentralization of power generation, and the emergence of new markets and new market structures.

In this context, Costa Rica is interesting from several perspectives.

On the plus side:

- **It was the first country in the region to introduce "access tariffs"** that seek to ensure the financial equilibrium of distribution utilities and thus solve the issue of network cost recovery that emerges as an increasing number of customers self-generate part of the energy they consume. Costa Rica has been willing to rapidly modify the relevant regulatory framework, as it learns from the mistakes and achievements of each set of regulations.[1]
- **It has introduced distributed solar and net metering without using fiscal subsidies,** in contrast with most international experiences of initial introduction of distributed solar, although, as we shall show, it has inadvertently provided incentives for solar adoption though the tariff structure applied to different types and sizes of consumers.
- **In terms of quality**, Costa Rica is moving into distributed power generation using the most advanced international regulations available, namely IEE 1547, to ensure that increased use of renewables-based distributed generation does not lead to lower quality of service to customers.

[1] In fact, a new set of regulations is being prepared as we complete this report.

- **Costa Rica has made the expansion of renewable power generation a national policy priority** but does not seem to have realistically taken into account the financial consequences of distributed power generation on distribution and generation state-owned utilities.

On the negative side:

- **Neither the access tariff nor the peak demand[2] charge have been properly designed.** Fixed costs are being allocated with volumetric charges, and some PV adopters are exempted from "demand charges"[3] if their total energy consumption is below a certain threshold.
- **The institutional architecture of power regulation** has not been updated to reflect the emergence of multiple actors in the power sector, the possibility of diverse market structures within the sector, or generally accepted good regulatory practices. The country has an outdated institutional architecture designed for monopoly regulation only, with ill-distributed functions among market operators, market regulators and energy policy authorities.

Additionally:

- **The power sector in Costa Rica is still dominated by state-owned utilities**, while most of the global discussion on distributed power generation regulation has taken place in open markets with privately owned utilities. In contrast, the participation of private actors in Costa Rica is limited, and there are regulatory barriers to entering the market.
- **Three large reservoirs in Costa Rica,** namely, Arenal, Angostura and Reventazón may be used as "water batteries," thus reducing the burden on the system as it integrates an increasing share of renewable variable power generation such as solar and wind. As generation using these sources increases, water could be saved during peak PV and wind generation hours and used for

[2] Which, like the access tariffs, is justified by fixed infrastructure costs.
[3] In this context "demand" does not refer to the economist's "demand curve," but to peak power demand.

generation in the evening, when demand increases and PV generation stops altogether.

1.2 Objectives

This paper has the following objectives:

- Provide a general characterization of overall power regulation (rules and institutions) and a detailed characterization of the ongoing evolution of distributed rooftop PV regulation in Costa Rica.
- Develop rooftop PV adoption models for residential consumers, commercial and mid-size industrial consumers, and for medium-tension industrial consumers.
- Evaluate maximum adoption rates under current regulations (which include arbitrary PV adoption limits and opportunities for regulatory arbitrage) and under alternative regulations, and evaluate the impact on the cash flow of distribution utilities under each scenario.
- Assess the institutional architecture of power regulation in Costa Rica and contrast it with international best practices / regulatory consensus.
- Based on the adoption simulation and the institutional assessment, prepare policy recommendations that might help Costa Rica achieve a better balance between conflicting regulatory goals through changes in regulatory rules and institutions, considering both the peculiarities of the Costa Rican case and the international experience in the regulation of distributed rooftop PV generation.

1.3 Working Hypotheses

- *Tariff structure and impact on distribution utilities*
    - The combination of a non-neutral tariff structure and volumetric-based grid access charges for PV installers currently in place creates the wrong incentives for PV adoption and will have large negative effects on the financial sustainability of distribution utilities.

- *PV adoption decision rules*
    - Residential customers will install rooftop PV if their (expected) electricity bill over the next five years is no higher than without PV, and lower over the five years after that.
    - Residential customers will not consider the (required) down payment for PV equipment when deciding whether or not to install PV.[4]
    - In contrast, industrial-commercial and mid-tension industrial customers will seek to maximize the NPV of their investment.
- *Institutional architecture*
    - The institutional architecture of power sector regulation in Costa Rica was designed for monopoly regulation of state-owned utilities, and it is therefore ill-equipped to deal with the regulation of the existing multi-actor power sector, which has emerged as a result of piecemeal regulatory reforms and emerging new technologies.
    - Accommodating the increased participation of new agents, a gradual increase in the share of variable renewable sources, and the transition from unidirectional power flows into bidirectional power flows will require new auxiliary services. The need for these services will demand the creation of new markets to enable the entrance of new service providers into the system.

1.4 Structure of the Report

In Section 2 we present the methodology used for the simulation exercises, and in Section 3, an overview of the electric sector in Costa Rica. In Section 4, we describe RPV distributed generation regulation. Pricing rules are presented in Section 5. In Section 6 we illustrate changes in residential, commercial and TMT monthly bills using different sizes of PV installations. In Section 7 we illustrate 10-year savings, considering not only changes in the electricity bill, but also the price of the PV equipment and the conditions under which it is financed. In Section 8 we illustrate the impact of shifting to a neutral pricing scheme. In Section 9, we put all the previous elements

[4] Readers may object that rational consumers would certainly take the down payment into account. What we are trying to do is approximate the actual decision criteria of consumers as evinced from conversations with PV equipment installers. At any rate, the main contribution of this paper is the development of simulation models whose premises could be changed in subsequent exercises. More on this below.

together and calculate optimal PV installation for all consumer sizes and types, and the net impact on distribution utility's revenues under current and under neutral pricing schemes. Conclusions and policy recommendations are presented in Section 10.

2. Methodology

2.1 Data

- Monthly invoicing data for all residential, commercial-industrial and mid-tension (TMT) consumers, grouped in 1 KW/h increments, for the year 2018.
- Tariff and other charges applied to electricity consumers, by consumer type and consumption volume.
- Tariffs charged to distribution utilities by generation utilities, by time block peak (valley, evening).
- Solar radiation estimates by hourly solar radiation data for the same year.

2.2 Construction of Synthetic Load Profiles by Hour and Month

From previous work, we have hourly consumption profiles for each type of consumer. We combine this information with the invoicing data to recreate hourly energy consumption for each consumer type and energy consumption level, as follows:

- First, we adjust the load pattern so that total consumption is equal to monthly consumption for each consumption level and consumer type. In other words, all residential consumers are assumed to have the same load pattern, but the level of the curve is adjusted to reflect the actual monthly consumption of each consumer group[5] and type.
- Second, we introduce some variability into the load profiles by allowing up to 10 percent random deviation from the estimated profile to account for variability.

[5] Recall that consumers are grouped in 1 KW/h increments.

- Third, the current tariff rates are applied to the synthetic load patterns, monthly electricity bills are generated, and the resulting invoicing is compared with actual invoicing to validate the model.

2.3 Changes in Billing and Grid Energy Consumption or Injection Using RPV

- For each consumer type and consumption level, we introduce PV installations, in 0.1 kW power increments for residential consumers, 1 kW increments for commercial-residential and 1 kW increments for TMT consumers.
- For each size installation, we then calculate grid consumption, self-generation, and energy injection into the grid.
- Based on the energy totals, we calculate the bills for each consumer considering the installation of the PV system and a counterfactual bill conditional on not having installed rooftop PV.

2.4 Installation Decisions by Consumption Levels and Consumer Type

- Next, for each consumer type and consumption level, we compare billings for ten years, for each PV installation size. Using the decision rules described in Section 1.4, we calculate optimal installation size for each consumer group and type under current tariff and taxation rules.

2.5 Impact on Distribution Utilities' Revenue

- For each consumer group and type, we then calculate the net effect on distribution utilities, which is a combination of changes in the energy purchased from generators as a result of consumer self-generation, and the times at which changes in energy purchased and sold take place. The net effect on distribution utilities will not be zero if consumers "deposit" and "withdraw" energy during different time blocks.
- We then add up over all consumer groups and types, to calculate the total net effect on the distribution utility's revenue.

2.6 Alternative Tariffs and Taxation Rules

- We repeat the whole exercise under "neutral tariffs" and taxation rules: all consumers are charged the same price for energy during each time block (peak, valley, evening), demand charges are applied according to actual demand for each consumer group and type, and the same taxes are applied to all consumption levels and consumer types.
- We then compare the results for consumers and distribution utilities under actual and "neutral" tariff and taxation rules.

3. Overview of the Electric Power Sector in Costa Rica

3.1 The Evolution of Power Sector Regulation

In 1989, the Costa Rican Congress became worried about the capacity of the state utility Instituto Costarricense de Electricidad (ICE) to fulfill the country's energy demand. Specifically, they were concerned about the high level of investment needed to expand the energy infrastructure, and the financial ability of ICE to meet that level by itself.

As a consequence, Congress passed a bill (Law 7200) to authorize the autonomous or parallel generation of electricity by cooperatives and private companies. The idea was to promote private investment in small hydroelectric plants around the country, guided by ICE's technical recommendations on potential sites and adequate power voltage.

Under Law 7200, private companies and cooperatives can enter into a concession contract with the public utilities' regulator to set up and operate limited-capacity power plants for a period of 20 years. The law initially required the companies' capital to be 65 percent Costa Rican. The current percentage is 35 percent.

The list of requirements for obtaining a concession for private generation of electricity is quite long, and the law has always been criticized for making it too complicated for the private sector to enter the energy business. The law requires ICE to determine the eligibility of the project, and it is not allowed to approve projects that generate over 15 percent of the national electric system's overall power capacity.

The first utility regulator in Costa Rica was called Servicio Nacional de Electricidad (SNE). It was created in 1928 (Law 77) at the same time that electric power forces were nationalized. Its

initial objective was to exploit the country's energy sources by itself and through concessions to third parties. In 1941, SNE's responsibilities were extended to include more regulatory functions.

By the 1990s SNE was widely considered an obsolete institution, and in 1996 Congress approved a law to create the Autoridad Reguladora de los Servicios Públicos (ARESEP). This was undertaken in order to overcome the three main problems presented by SNE: i) lack of independence from the Executive in the tariff-setting process, ii) a conflict of interest with regulated entities derived from the funding model of SNE, and iii) a lack of organizational capacity required to function as an adequate public service regulator. ARESEP was therefore conceived as a modern and highly technical institution able to regulate public services efficiently and provide a balance between consumers and utilities.

Rural electrification cooperatives have existed in Costa Rica since 1964. These non-profit organizations were created to bring electric energy to remote rural areas that would otherwise be left without power, by purchasing electricity from ICE and distributing it across their area of coverage.

In 2002, Congress started discussing a law to allow rural electrification cooperatives to generate electric power, become self-sufficient and add electricity to the grid. Congress considered that the cooperatives had done a good job so far, were efficient and were financially healthy enough to carry out larger-scale projects. They also worried that cooperatives' rates would increase if they kept buying energy from ICE instead of generating new energy. The project's main objective was to allow cooperatives and municipal electric companies to develop hydroelectric energy projects, generate electricity and sell it to its users, and also sell to ICE.

The bill also attempted to solve a legal void caused by the creation of ARESEP, which repealed the SNE Law and consequently its regulations. The latter contained a detailed legal framework for granting concessions on public water use for electric power generation. Although Law 7200 allowed for concessions in this regard, the Procuraduría General de la República (PGR) and the Constitutional Court both agreed that it did not provide a sufficiently comprehensive legal basis for the State to grant this kind of concessions. The bill, which eventually became Law 8345, contained the missing legal framework to allow the Ministerio de Ambiente y Energía (MINAE) to grant the concessions to cooperatives and municipal electric companies.

Between 2010 and 2011, the Executive rallied to pass bills to open the electricity market. In 2010, President Oscar Arias presented to Congress a bill to create a "General Electricity Law,"

which aimed to open the electric power market and dissolve the legal barriers to accelerating investment in this area. The bill was not approved, as President Arias' political capital had already been spent in the struggle to approve a very controversial free trade agreement with the United States. His successor, President Laura Chinchilla, did not promote the original bill in Congress, but presented another bill which established a more conservative approach to opening the market. Even though none of the bills were successful, they started a discussion on the pros and cons of opening the electricity market in Costa Rica.

In 2010 ICE introduced a research and development project called Distributed Generation for Self-Consumption Pilot Plan. The Plan's main objective was to gauge users' interest in distributed generation using renewable energy sources, as well as to allow ICE to gain experience in this regard and evaluate the impact on the distribution grid. The project was supposed to end in 2012 and was assigned a 5MW capacity, but due to the number of applications it was extended three more years and its capacity was increased to 10MW. The plan effectively ended in February 2015, although the generation projects set up under the plan are still operating.

ICE's Pilot Plan was the first initiative of this kind, generating mostly interest in photovoltaic generation. The Plan established 1 MW of capacity for residential use.

As the project was undertaken for experimental purposes, all metering, processing and inspection costs were borne by ICE, and there was no access charge for the participants, although they had to cover all installation, operation and maintenance costs. Users interested in participating in the Pilot Plan were required to file an application and ultimately sign a connection agreement with ICE. Although the agreement had a 15-year term, participants could opt out at any time. As energy surpluses poured into the grid were not paid but credited towards future consumption, the main benefit for participants was the reduction in their monthly electric bill.

In April 2011, MINAE published a Directive (Directive 14-2011) calling on the institutions of the electric sector to develop initiatives to promote the use of distributed generation for self-consumption with renewable energy sources. The Directive came after ICE had launched the Pilot Plan and did not have a significant impact on the rest of the electric sector, as no other entity executed a similar project. However, it marked the Executive's formal support for this technology and, most importantly, urged ARESEP to create proper regulation on distributed generation for self-consumption.

At the same time Directive 14-2011 was issued, MINAE issued Directive 15-2011, which intended to promote private electricity generation with renewable sources under Law 7200. The Directive demanded ARESEP to establish tariff regulation to promote this kind of projects and requested ICE to develop a plan to implement private generation projects in order to fulfill the capacity allowed by Law 7200. MINAE also called on distribution companies to develop renewable energy projects to meet the energy demand of their own areas and of the rest of the country through collaboration with ICE.

This Directive enabled a new scheme of project selection contests, in which ARESEP established a tariff range (as opposed to pre-defined tariffs) for various "power blocks," e.g., a wind power block of 100 MV. ICE determined which projects were eligible for participation and established the terms of reference of each contest.

In 2012, the Contraloría General de la República issued an audit report on the capacity and performance of the high voltage transmission lines network, which belong to and are operated by ICE. The Contraloría found that ARESEP had not issued adequate regulation to ensure the operational safety of the transmission lines and required ARESEP to issue proper regulation in the short term.

As a consequence, in April 2014 ARESEP issued regulation AR-NT-POASEN (*Planeación, Operación y Acceso al Sistema Eléctrico Nacional*, "POASEN"), which provides general rules for all actors in the electric system regarding their functions, as well as all technical, contractual, commercial and tariff-related conditions to connect to the national electric system.

POASEN is currently the central regulatory body of the Costa Rican electricity sector. It establishes guidelines for all actors involved in the generation, transmission and distribution of electricity, related to the following aspects: meeting the demand of electric energy, access, expansion, operation (which includes all the planning, coordination, supervision and control), topology, and the performance of the national generation park and the national transmission network.

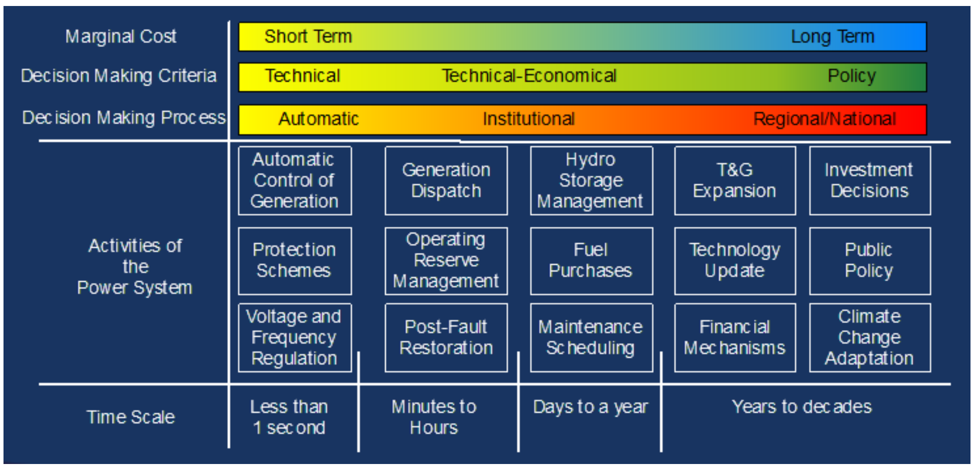
POASEN includes regulations for distributed energy generation, although it was subject to a very relevant reform in this regard in 2016, as explained further in this report.

Box 1. In Search of Responses to New Technologies and New Market Structures

From a technical point of view, electric power systems have developed more or less in the same fashion over the last 100 years everywhere. The characteristics of the product they are designed to produce and deliver results in a hierarchical organization structure. Electricity is generated in large facilities, transported through high-voltage transmission lines and delivered to customers via radial distribution systems. Also, the whole system is dominated by electromagnetic physics and conditioned by the fact that supply and demand must be in instantaneous and permanent balance at every scale in the system.

The technical characteristics of the system profoundly influence the regulation and institutional arrangements, Figure 1 shows the different activities in the electric power system and the relationship they have with the decision-making processes in operation and regulation. Until the first wave of utilities unbundling in the United States and the United Kingdom, the system has been managed as a vertically integrated business.

Figure 1. Electric Power System Activities across Time Scales



Source: Author's compilation.

Despite the technical similarities between systems, unbundling of the sector has taken many flavors depending on a series of local characteristics. In some cases, generation and retail function under competitive market structures, while transmission and distribution have been deemed natural monopolies and operated as regulated monopolies.

Since the seminal work by Schweppe on marginal pricing of electricity (Schweppe et al., 1988), regulators and practitioners have attempted to approximate the application of these principles to improve economic efficiency in the sector. The most widely used application of these principles is Time-of-Use (TOU) rates for consumers.

After the unbundling wave during the 1990s and the first market restructuring in the early 2000s, regulatory practices in the electric sector have not changed substantially.

Moreover, the regulatory innovations from this period were done under a passive consumer behavior paradigm and with a generation mix dominated by hydro or thermal generation.

The upcoming wave of technology innovations is reconfiguring the supply chain of the electric sector and with it the regulation of the sector. Renewable energy at zero marginal cost, distributed resources, demand response and energy storage, are among the critical disruptors in the sector and enables of new market arrangements.

3.2 Main Actors in Planning and Regulation

The regulation of the electric sector in Costa Rica is currently in charge of three entities: the Ministerio de Ambiente y Energía (MINAE), which is part of the Executive branch, a State-owned enterprise called Instituto Costarricense de Electricidad (ICE), and the public services regulator, the Autoridad Reguladora de los Servicios Públicos (ARESEP).

3.2.1 ICE and MINAE

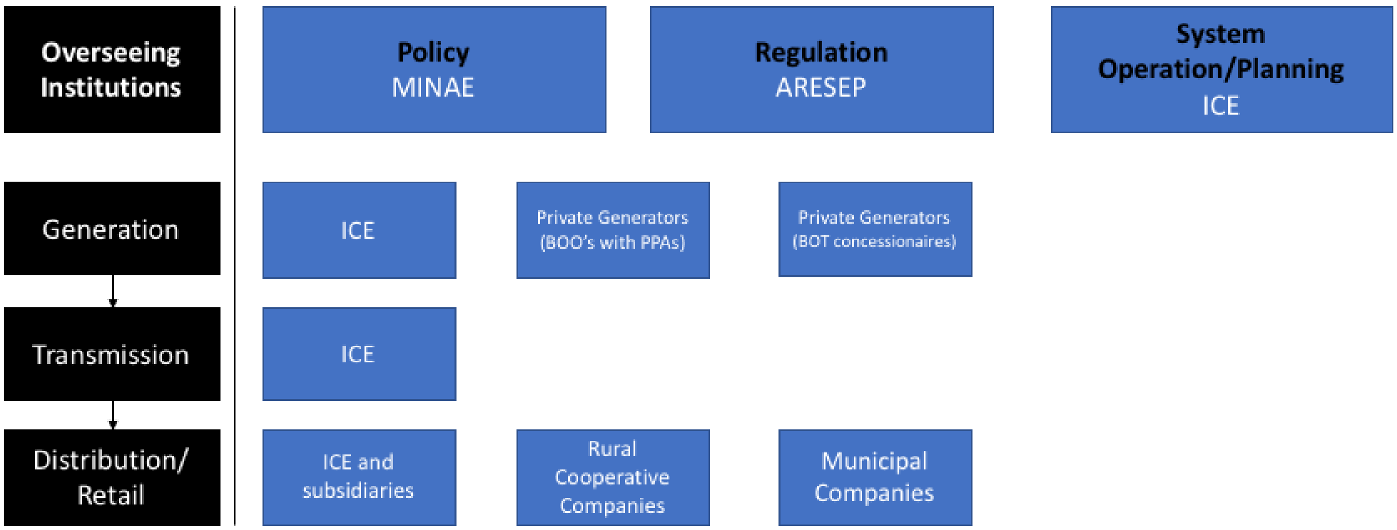
In light of the technological shift that is currently taking place in the energy sector, one of the critical adjustments needed is the redesign of its planning scheme. As the energy sector in Costa Rica becomes increasingly decentralized, there will be less certainty in the planning function and regulating entities will struggle to adjust to the fast-paced technological changes taking place on the consumers' side. As explained below, the planning scheme of the electric sector in Costa Rica is fundamentally flawed.

As the governing entity of the energy sector, MINAE is responsible for directing and coordinating the creation of public policies and strategies involving energy issues throughout the nation. MINAE is in charge of overseeing and evaluating the performance of all institutions that are part of the energy sub-sector, including municipal companies and cooperatives providing public services, and of establishing integration mechanisms for the different actors to exchange ideas on relevant matters. Together with the President, MINAE is in charge of approving the National Energy Plan, in accordance with the National Development Plan.

ICE is a public-private company that operates as an autonomous institution, meaning it has administrative independence but is, in principle, subject to public development policies issued by the Executive. It was created in 1949, as the entity in charge of the rational development of energy sources in Costa Rica. The main resource in mind at that time was water, therefore the law that created ICE states as its main responsibility the management of hydroelectric energy for the benefit of the country.

The electricity sector is vertically integrated, with most activities in the supply chain undertaken by ICE, including some of the vital oversight tasks. This structure is similar to that in other Latin America countries such as Paraguay and Uruguay and, at the local level, Colombia and Brazil. Figure 2 presents the current framework.

Figure 2. Costa Rica's Institutional Arrangement of the Electricity Sector



Source: Author's compilation.

ICE operated as a monopoly in electricity generation, transmission and distribution for many years, and although other actors have been allowed to participate (to some extent) in the generation and distribution activities, ICE plays a crucial role in the energy sector. Not only is ICE the main generator of electricity, but it also owns all the transmission lines in Costa Rica, is responsible for ensuring the electric energy supply and is the only company allowed to trade electricity in the Regional Electric Market (MER).

Derived from ICE's duty to ensure the supply of electricity to the whole country, the historic interpretation has been that ICE is the entity responsible of planning for the national electric expansion and development, doing so through its Dirección de Planificación y Desarrollo Eléctrico (Electric Planning and Development Office).

Moreover, ICE owns the national dispatch center (the Centro Nacional de Control de Energía, CENCE), which is in charge of operating the National Electric System under ARESEP's regulations and trading electricity in the MER. Most importantly, CENCE is in charge of planning

the use of resources for generation and transmission in the National Electric System, under its own self-defined planning strategy. The main objective of its planning functions is to meet energy demand in the country. To this end, CENCE is allowed to require all information needed to update its annual planning from generators, distributors, consumers and high-voltage users.

Consequently, even though MINAE should in principle carry out its planning through the National Energy Plan, in practice its function is limited to providing general policy guidelines, while ICE establishes the goals and procedures that define the development of the electric sector. ICE is also better equipped on technical matters than MINAE, in terms of staffing and data availability (e.g., MINAE's National Energy Plan is largely based on the information submitted by ICE).

ICE's dual role as a regulated entity and planner of the energy sector clearly represents a conflict of interest. For this reason, we argue that the planning of the energy sector should be carried out by an impartial third party with no commercial interests, in order to ensure this long-term planning is defined in the country's best interest, which may not always match ICE's. Furthermore, under current regulations, MINAE lacks tools for real control over ICE's operation: ICE's expansion and development plans are based solely on ICE's criteria and are not subject to revision or approval by MINAE.

3.2.2 ARESEP

ARESEP plays a key role in the energy sub-sector. In the past, the government used to manipulate prices to gain public support or balance the budget. The creation of ARESEP made that kind of behavior impossible.

ARESEP, as the public service regulator, is in charge of setting prices and tariffs for all public services, safeguarding their quality, quantity, continuity and optimal service, and ensuring a balance between users' and utility companies' interests and necessities. To this end, ARESEP issued POASEN, which establishes the technical rules for the development, technical operation and access to the National Electric System in the all stages of the electric supply.

ARESEP is required to set prices under a cost-of-service principle. Although this principle is designed to ensure the appropriate development of the activity, and the costs must be limited to those strictly necessary to achieve this, the method has been criticized for providing insufficient

incentives for financial discipline and good planning or investing in technologies to improve efficiency.

Moreover, in the context of the electric market explained above, the regulator is somewhat weak vis-à-vis the utility. Public and political support concentrates around ICE, and it is difficult for the regulator to maintain its independence. Moreover, the incentive problem is more severe in public than private enterprises, since the former do not respond to profit levels and the ratepayer always bears the costs (including fines, as a consequence of the cost-of-service principle). Therefore, the question of how to make the monopolist efficient remains open.

Private firms, on the other hand, respond to prices and profits. The regulator, however, experiences difficulties in obtaining the relevant information to set prices and perform its regulatory functions. The firms are aware of this situation and manipulate the information they provide. Although Costa Rica's regulatory framework allows for the use of standardized model-firms for different sources of energy, this practice sometimes conflicts with cost-of-service regulations.

In Lara et al. (2015), the authors developed a set of indicators to measure the operational efficiency of generation distribution utilities in terms of reported statistics. However, this has not been implemented as policy due to the utilities' refusal to provide information: their attitude illustrates the political challenges the regulator faces in adapting to new technologies and finding opportunities to regulate them effectively.

3.3 Main Actors in Generation, Transmission and Distribution

3.3.1 Generation

The result of the legal scheme explained above is that the most significant share of electric power generation is handled through government-owned companies with smaller shares of private participation via Build Operate Own (BOO) and Build Operate and Transfer (BOT) schemes. Private firms operate under energy transactions through Power Purchase Agreements (PPAs), with tariffs established by ARESEP (as per Law No. 7200). Modifying this structure is not an easy task given that there is no evidence that a competitive market for power generation can function in Costa Rica. This issue has been extensively discussed in Cornick and Lara (2016), where the authors analyzed the technical issues regarding rate-making and industrial consumers' electricity costs.

ICE is the biggest generator in the country, with 32 plants that represent 69 percent of the total installed capacity in 2018. Most of the energy produced by ICE is hydroelectric (67 percent) followed by thermal (23 percent) and geothermal (9 percent). The only solar plant operated by ICE is Solar Miravalles, a small 1000 kW plant created in 2012 and located in Guanacaste.

Private generation under Law 7200 (i.e., private generation for public use, under concession agreements granted by MINAE) represents 19 percent of total installed capacity in the country. This type of generation uses mostly wind and hydroelectric plants. Like ICE, solar energy is the smallest installed capacity by private generators, with only 10.08 MW as of 2018.

The estimated current installed capacity in distributed generation for self-consumption is 20 MW. Most of these prosumers operate through interconnection agreements with ICE and CNFL. Distributed generation for self-consumption is most popular among commercial and residential users.

There are currently two municipal companies that generate and distribute electricity: the Junta Administrativa de Servicios Eléctricos de Cartago (JASEC) and the Empresa de Servicios Públicos de Heredia (ESPH), established in 1964 and 1976, respectively.

Moreover, there are four rural electrification cooperatives operating in Costa Rica: Coopeguanacaste, Coopelesca, Coopesantos, and Coopealfaroruiz, plus a consortium of the four original cooperatives called Conelectricas. These are non-profit entities founded between 1965 and 1972 to provide electricity to remote rural areas.

Municipal companies and rural electrification cooperatives together have 7 percent of total installed capacity. Cooperatives own 12 energy plants, eight of which are hydroelectric. They also have three wind plants and a 5023-kWh solar plant in Guanacaste. JASEC and ESPH operate eight plants, all hydroelectric.

3.3.2 Transmission

ICE owns all transmission lines in Costa Rica. As of 2017, the transmission system was comprised of 2375 km of transmission lines, distributed in 1723 km for 230 kW voltage, 652 km for 138 kW voltage, and 102 sub-stations.

3.3.3 Distribution

ICE and CNFL act as distributors for over 76 percent of total users in Costa Rica. Table 1 shows the number of clients per distribution company, by rate category. In addition to these, as of 2017,

there were 11 high-voltage clients, who do not use the distribution system, and instead are supplied directly by ICE.

Table 1. Number of Users per Rate in December 2018

	Medium Voltage	Commercial	Industrial	Residential	Social
ICE	664	89,228	3,549	686,876	6,847
CNFL	289	70,376	1,474	492,963[6]	2,616
Municipal Companies and Cooperatives	57	51,977	3,688	358,055	1,793

Source: ARESEP.

3.3.4 Share of Sectoral Income

Table 2 shows the share of sectoral income accrued to each company in the electricity sector for the period 2013/2017. Ninety-three percent of income corresponds to sales by public companies, including government-owned, cooperatives and municipal ones. They are in charge of generation and distribution, and ICE has the monopoly over the transmission sector. Private generators produce only 7 percent, and all of them are required to sell to one of the government-owned companies or cooperatives. ICE also has a high rate of approval for the quality of its service in the population at large, although there is a significant proportion that complains about high costs. It is an extensive monopoly with a high level of legitimacy.

[6] Includes users in residential, hourly residential and promotional rates.

Table 2. Share of Income by Company

Regulated company	Average Income 2013/2017 (Costa Rican colones)	Share of Income 2013/2017
Total	1,528,861,254,646	100%
Government-owned, cooperatives and municipal firms	1,414,668,277,798	93%
ICE	932,871,310,689	61%
CNFL	310,826,376,275	20%
ESPH	43,204,253,498	3%
JASEC	42,232,624,912	3%
Coopelesca	37,149,535,767	2%
Coopeguanacaste	35,625,143,216	2%
Coopesantos	10,576,129,253	1%
Coopealfaro.	2,182,904,188	0%
Main Private operators (generators)	114,192,976,848	7%
Unión Fenosa Torito	12,018,362,496	1%
Unión Fenosa La Joya	9,795,239,437	1%
Consorcio Eólico Chiripa S.A.	9,732,252,266	1%
Coneléctricas (VIII)	8,132,484,019	1%
Planta Eólica Guanacaste S.A.	8,098,651,476	1%
Hidroenergía del General S.R.L.	7,962,564,140	1%

Source: ARESEP

4. Rooftop PV Regulation

4.1 POASEN and Simple Net Metering

With the cost reductions in solar panels and the increases in retail tariffs, rooftop Photovoltaic (PV) adoption has risen steeply, with approximately new 360 systems installed per year. As a response to the adoption of distributed solar in Costa Rica, the regulator approved POASEN. An in-depth analysis of the technical standard and its implications for distributed generation is presented in Lara et al. (2015).

This regulation has sparked conflict between the different oversight institutions, and a haphazard solution to the legal vacuum has been to split the responsibilities between the Ministry that licenses the PV systems and the regulator that created grid-access tariffs and established adoption limits (i.e., installed capacity cannot be greater than 15 percent of peak demand). These policies were analyzed in detail by Lara et al. (2015, 2018) for the most extensive distribution utility in Costa Rica (CNFL). The findings show that the implementation of access tariffs is not sufficient to compensate for the loss of revenue from the utilities. The analysis shows that the

combination subsidy polices for residential consumers and the adoption of rooftop solar creates incentives for large consumers to adopt distributed PV at the expense of other consumers.

In June 2015, MINAE filed a consultation with the *Procuraduría General de la República* asking whether distributed generation of electricity for self-consumption was considered a public service, and therefore subject to the concessions' legal framework. The consultation was limited to distributed generation for self-consumption under the net-metering billing mechanism, i.e., without selling excess electricity to the distribution company.

ARESEP was asked to provide comments on the subject. They argued that, even though net-metering mechanism did not involve the sale of electricity for public use, the fact that the user had to connect to the grid was enough to consider it a public service, since this connection impacted the whole system, which worked to provide electricity to all other users.

The *Procuraduría* concluded that this kind of generation was not a public service, because the key element for considering an activity as such is that it addresses a necessity considered of general interest, which was not the case under the net-metering scheme.

The relevance of this legal opinion cannot be understated, as distributed generation for self-consumption under the net-metering model was virtually impossible before the *Procuraduría* clarified it is not a public service. The regulation for granting concessions for electricity generation is contained in Law 7200, which was intended to regulate private generation with small hydroelectric plants, a far more complicated matter than generation for self-consumption. Under this legislation, granting a concession agreement entails a series of requirements and processes that are not appropriate or convenient for a user looking to set up a small rooftop photovoltaic power station or mini-hydro generator. Furthermore, the *Procuraduría* concluded that the conditions for connecting to the grid must be established in a connection agreement to be subscribed between the generator and the distribution company, and that this agreement has to comply with ARESEP's technical rules.

In September 2015, MINAE published Decree No. 39220, called Regulations on Distributed Generation for Self-Consumption using Renewable Sources, under the Net-Metering Contractual Model. The decree was a product of the *Procuraduría's* legal opinion issued in June that same year and aimed to fill the regulatory vacuum regarding the implementation of distributed generation for self-consumption.

The decree sets the competencies of each actor of the electricity sector regarding this type of generation, mainly assigning responsibilities to the *Dirección de Energía* of MINAE and the distribution companies. It requires distribution companies to carry out a technical study in order to determine the maximum power capacity of each of its circuits.

Users interested in setting up a distributed generation system for self-consumption must file a request before the distribution company, to verify the circuit's available capacity. The decree establishes that the maximum capacity of all generation systems connected to a circuit cannot exceed 15 percent of maximum annual power demand.

In its transitory provisions, the decree ordered ARESEP to adjust its existing regulation to the decree's content. In addition, it reaffirmed that the conditions under ICE's Pilot Plan remained valid for its participants until their connection agreements expired.

In February 2016 ARESEP issued a second version of POASEN, as demanded by MINAE and the *Procuraduría General de la República*, following Legal Opinion 165-2015 and Decree 39220. In this second version, ARESEP introduces new provisions for distributed generation for self-consumption under the net-metering model according to the concepts described by MINAE in Decree 39220; it also establishes certain waivers for users generating electricity under this modality.

In the same resolution that approved the changes in POASEN described above, ARESEP approved a cost-based tariff methodology to access the grid under these connection agreements, which takes into consideration the distribution companies' costs of operation, maintenance and administration related exclusively to distribution activity.

4.2 Rules and Obstacles for PV Adoption

The Costa Rican territory has one of the best solar radiation conditions in the world, and therefore it is possible to install efficient photovoltaic generators almost throughout the entire country.

Due to current regulations and specifically the issuance of Decree 39220, the main interest in the Costa Rican market regarding distributed generation is focused on photovoltaic generation for self-consumption.

It is important to note that there are currently a few very small photovoltaic generation farms around the country that operate under Law 7200, with installed capacity ranging between 1MW and 5MW. These are owned by distribution companies and cooperatives.

Under Decree 39220, prosumers are allowed to add surplus power to the grid and consume it during the following 12-month period, as long as the excess energy does not exceed 49 percent of total energy produced. Therefore, if more than 49 percent of the total generated energy is poured into the grid, the distribution company will not credit that excess for consumption in the following months.

Moreover, the maximum capacity of all generation systems connected to a circuit cannot exceed 15 percent of maximum annual power demand. This 15 percent limit was not determined on a technical basis; it is rather a sort of arbitrary limitation to avoid excess generation that could affect the national electric system. Furthermore, prosumers argue that even in circuits that have technically reached their full capacity, engineering solutions could make it possible for distributed generators to connect without affecting the system.

There is not yet an adequate regulatory framework for distributed generation for self-consumption out of the net-metering model, i.e., allowing users to sell the excess electricity they pour into the grid. This situation exists because selling excess electricity would require prosumers to apply for a concession agreement under Law 7200, as the sale would be considered a provision of a public service. As explained above, Law 7200 is a set of rules designed mainly for private generation projects such as limited-capacity hydro power plants and therefore represents more obstacles than incentives for self-consumption generators.

MINAE is currently working on a reform to Decree 39220. During 2018 the *Dirección de Energía* of MINAE held two workshops with several actors of the electric sub-sector to gather feedback on the implementation of the Decree during the past three years.

The main concerns among prosumers are related to the 49 percent and 15 percent limits explained above, and the administrative burdens associated with the implementation of the net metering model. Regarding the latter, prosumers have expressed complaints on the lack of clarity and accountability within the distribution companies during the implementation of administrative procedures required to subscribe connection agreements. In addition, specific requirements and deadlines vary among the companies, causing unnecessary burdens and delays. Furthermore, the practicality and technical adequacy of the 15 percent and 49 percent limits was strongly questioned.

The new version of the Decree was expected to be published during the first semester of 2019.

5. Pricing Rules and Taxation

5.1 General Pricing Rules

In Costa Rica, the regulator uses three major classes of consumers to set the rates depending on their total energy consumption and power requirements. This section describes the characteristics and costs of each tariff and the common load curve per customer type. The economic feasibility of installing a PV system greatly relies on those two components, both subject to regulation. There are three main types of consumers, as discussed in the subsections below.

5.1.1 Residential

The electricity tariff for residential consumers is set within an increasing block pricing scheme, as shown in Table 3.

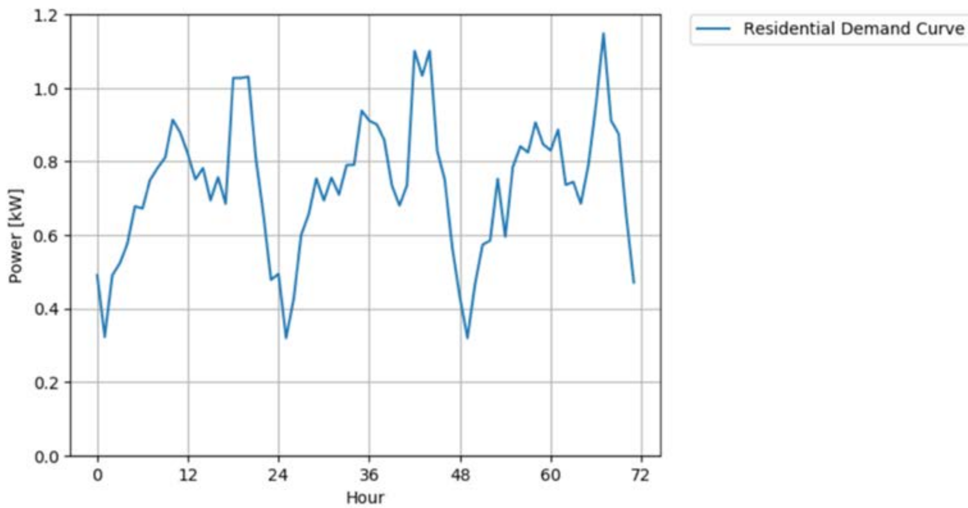
Table 3. Tariff Scheme for Residential Consumers

Blocks	Range	Price ₡/kWh
a	0-30 kWh	2,156.10
b	31-200 kWh	71.87
c	201-300 kWh	110.30
d	> 300 kWh	114.02

Source: ARESEP.

A depiction of three days of a common load curve for a large residential consumer (550 kWh/month on average) is shown in Figure 3.

Figure 3. Load Curve for Large Residential Consumer



Source: Author's compilation.

5.1.2 Commercial – Small Industrial

This tariff applies to consumers with consumptions between 0 and 10,000 kWh/month. All consumers below 3000 kWh/month are subject to energy charges only. Consumers above that threshold are subject to demand charges. Demand charges are also applied by blocks. If demand charges apply there is a fixed cost for the range 0-8 kW and above that the cost increases by unit. The details of the tariff system are shown in Table 4 (demand charges are calculated with the maximum peak over the month).

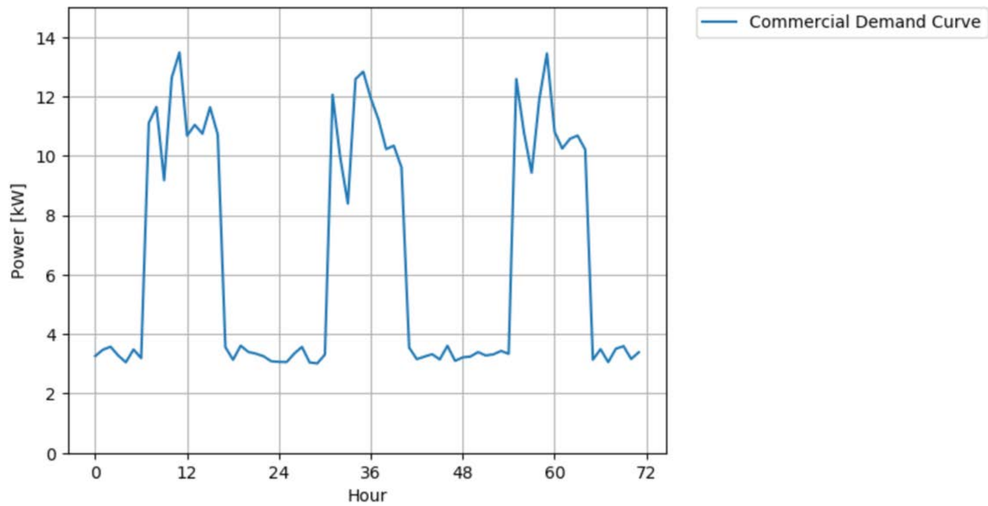
Table 4. Tariff Scheme for Commercial - Industrial Consumers

Block	Price
Block <= 3000 kWh	121.46 ₡/kWh
Cost of first 3000 kWh	219,360.00 ₡
Block > 3000 kWh	73.12 ₡/kWh
Cost for the range 0-8 kW	91,569.68 ₡
Demand > 8 kW	11,446.21 ₡/kW

Source: ARESEP.

A depiction of three days of a common load curve for a medium size commercial consumer, 5000 kWh/month on average and 13.84 kw-peak/month is shown in Figure 4. Commercial consumers are characterized by having a great part of their consumption during the day and a peak between noon and 7 pm.

Figure 3. Commercial Load Curve



Source: Author's compilation.

5.1.3 Medium Voltage (TMT)

These are consumers with an average energy consumption above 10,000 kWh/month and metered directly at the medium voltage level, hence the name TMT (*Tarifa Media Tensión*). These consumers are charged in a Time-Of-Use (TOU) fashion with three main blocks of time:

- Peak: 10:01 am – 12:30 pm and 17:31 pm-20:00 pm
- Valley: 6:01 am – 10:00 am and 12:31 am – 12:31-17:30 pm
- Night 20:01 pm – 6:00 am

Charges are calculated for each time block as the sum of the total energy per period and the maximum demand in the period during the month. The costs per period for energy and demand are shown in Table 5.

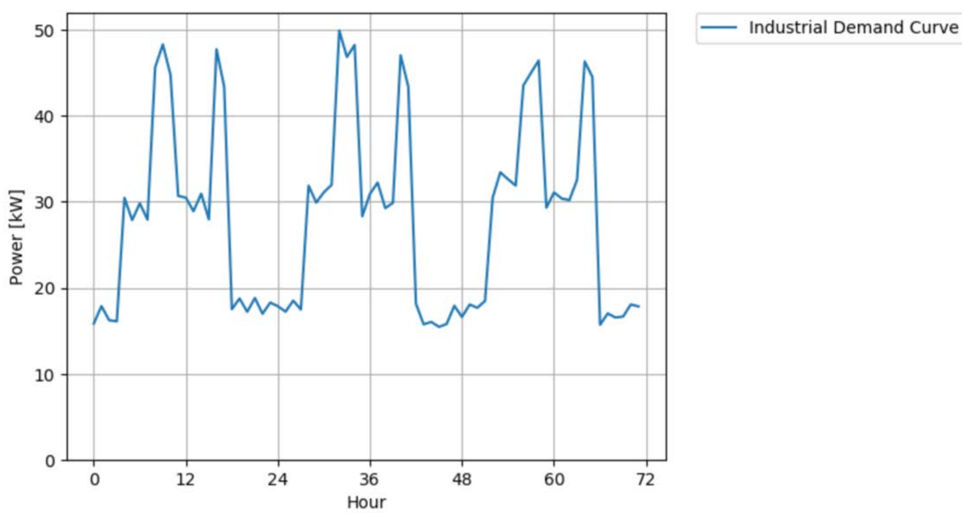
Table 5. Tariff Scheme for Large Industrial (TMT) Consumers

Energy Time of Use	**Cost**
Energy Peak	61.96 ₡/kWh
Energy Valley	30.99 ₡/kWh
Energy Night	22.31 ₡/kWh
Demand Time of Use	**Cost**
Demand Peak	10,864.99 ₡/kW
Demand Valley	7,730.78 ₡/kW
Demand Night	4,902.09 ₡/kW

Source: ARESEP.

A typical demand curve for a medium-size industrial consumer with monthly consumption of 20,550 kWh is shown in Figure 5. Industrial consumers are characterized by a profile with two peaks depending on production shifts, and if there is no night shift consumption goes down overnight.

Figure 4. Industrial Consumer Demand Curve



Source: Author's compilation.

The consumer characterizations shown here will be used in the forthcoming section to explain the method used to evaluate net metering regulation in Costa Rica and to validate the model.

5.2 *Energy Prices for the Distribution Utilities*

The price of bulk energy purchases from distribution utilities is also relevant in this context, given that the adoption of rooftop PV systems also affects energy purchases from the bulk power system. The pricing of bulk energy purchases is also based on a Time-Of-Use (TOU) structure for both power and energy with three main blocks of time.

- Peak: 10:01 am – 12:30 pm and 17:31 pm-20:00 pm
- Valley: 6:01 am – 10:00 am and 12:31 am – 12:31-17:30 pm
- Night 20:01 pm – 6:00 am

Table 6. Tariff Scheme for Distribution Utilities

Energy Time of Use	**Cost**
Energy Peak	53.98 ₡/kWh
Energy Valley	44.22 ₡/kWh
Energy Night	37.54 ₡/kWh
Demand Time of Use	**Cost**
Demand Peak	2,863.19 ₡/kW
Demand Valley	2,863.19 ₡/kW
Demand Night	- ₡/kW

Source: ARESEP.

Bulk purchases further include an added cost calculated every three months to account for fossil fuel generation. This increase factor is not included in our analysis since in the last three years it has generated no more than a 2 percent increase in average tariffs.

5.3 *The Regulatory Model for Net Metering in Costa Rica*

MINAE defined a new methodology to determine those kWh subject to a cost for accessing the grid, and those kWh subject to a conventional cost according to the electricity rate currently in force. This methodology can be explained with the definition of some terminology to make the presentation clear. The following terms are presented in the same order as they are calculated in the model, since the limits on energy withdrawal are set by cumulative sums.

- **Consumer energy:** Consumption of energy by the client in kWh, equivalent to the area behind the demand curve for the current month *(m).*

- **PV energy:** Solar generation produced in kWh by the rooftop system in the current month *(m).*
- **Injection into the Grid:** The flow of energy from the solar photovoltaic system into the grid in kWh during the current month *(m).*
- **Grid Energy:** Energy supplied to the consumer from the distribution grid during month *(m).* Total energy is the sum of withdrawn energy (WE) and utility supplied energy (USE) defined later.
- **Global generation:** Cumulative sum of the energy from the rooftop PV system during the year up to the current month *(m).*
- **Global withdrawal:** Cumulative sum of the withdrawn energy during the year up to the previous month *(m-1).*
- **Global allowance:** Maximum amount of energy that has been injected into the grid that the consumer can use in forthcoming months. Corresponds to 49 percent of the cumulative global generation per month *(m)* minus the global withdrawal as follows:

$$GA(m) = 0.49(global\ generation(m) - \ global\ withdrawal(m-1))$$

- **Allowance:** Energy available for withdrawal from the grid by the consumer during the month *(m)*. Defined as the minimum between the sum of the month's injection and the carryover, and the global allowance as follows:

$$A(m) = \min\left(injection(m) + carry\ over(m-1), GA(m)\right)$$

- **Withdrawn energy:** Energy withdrawn subject to the "grid access" tariff, in kWh. The maximum energy that can be accounted as withdrawn is the total injection during the month *(m).* Limits the withdrawal to the minimum between the allowance and the difference between injections and global energy supplied from the grid.

$$WE(m) = \min\left(\min\left(grid\ energy(m), injection(m) + carry\ over(m-1)\right), A(m)\right)$$

- **Utility-Supplied Energy:** Portion of the energy from the grid subject to the utility's tariff.

$$USE(m) = \max\left(0, grid\ energy(m) - \ injection(m) - \ carryover(m-1)\right)$$

- **Carryover:** Energy accumulated during a month for use in the following month. This is the remainder energy injected into the grid that the consumer did not withdraw during the same month.

$$carryover(m) = \max(GA(m) - WE(m), 0)$$

For the sake of explaining the process, the following examples show how several consumers and PV system configurations are charged for electricity and the net impact on utility's revenue that ensue.

6. Changes in Consumer's Bills and Utility's Net Revenue

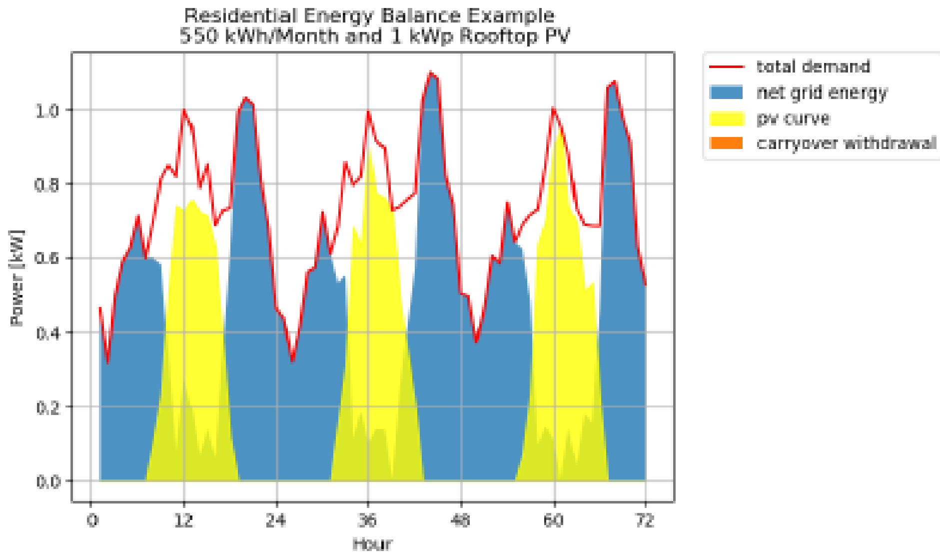
As indicated before, load patterns have been estimated for each type of consumer (residential, commercial-industrial and MT), and curve levels have been adjusted so as to match real consumption for consumers grouped in 1 KW/h intervals. Then, we have simulated the impact of PV installation of different sizes. In this section we illustrate the procedure for each type of consumer, using a fixed consumption level and different size PV installations.

6.1 Residential Consumers

Figure 6 illustrates 72 hours of energy demand and PV generation in the case of a 550kWh/month residential consumer with a small RPV installation.[7] In this case, grid energy demand is reduced by PV generation, but the consumer never produces surplus energy to be injected back into the grid.

[7] In the simulations to be presented later, the information is processed for each consumer group for a full year.

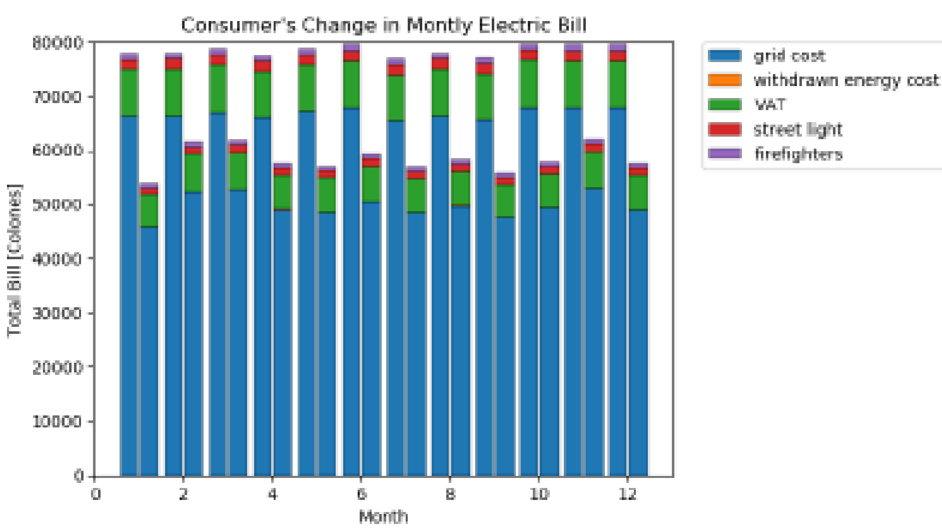
Figure 5. Case 1: 550 kWh/month Residential Consumer with 1kWp



Source: Author's compilation.

This small PV is enough to generate savings that average 25 percent of the consumers monthly bill, as illustrated in Figure 7.

Figure 6. Changes in Monthly Bill for Case 1



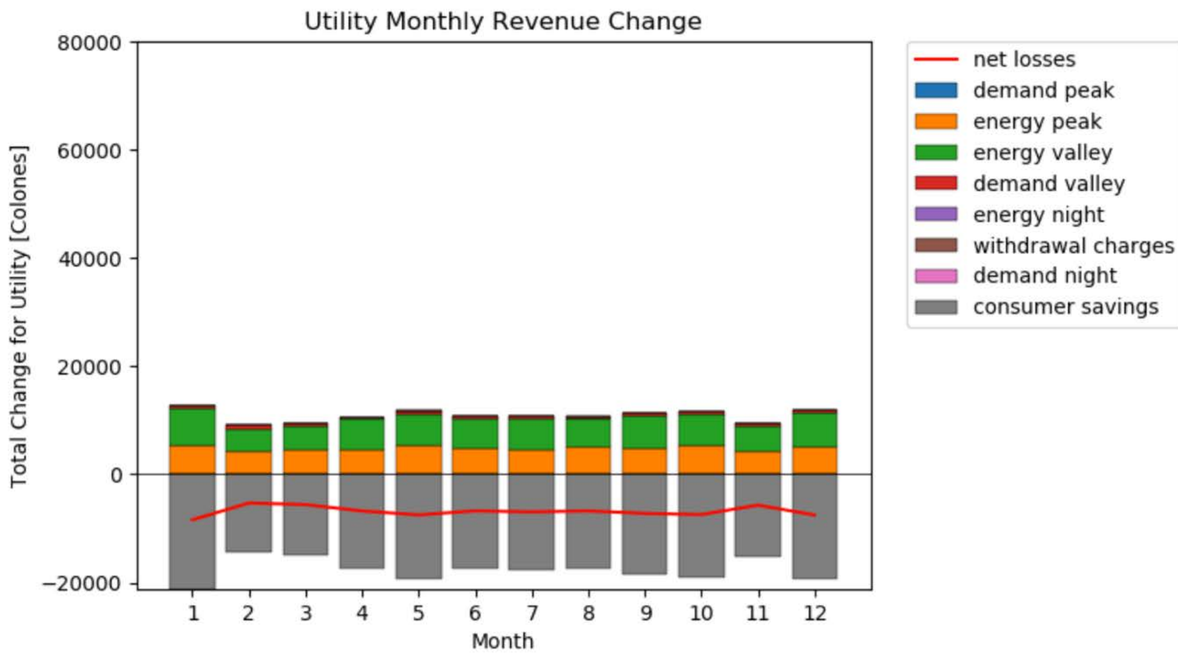
Source: Author's compilation.

The net effect on revenue for the distribution utility will be the sum of reduced revenue accruing to the utility from the consumer, and reduced payments from the distribution utility to the generating utility as a result of the consumer's RPV generation.

Recall, however, that prices charged for residential consumers depend only on total energy consumption within an increasing block pricing scheme (Section 5.1.1), while distribution utilities are charged for energy at different prices according to the time of the day (Section 5.2). In Figure 8 the consumer buys less electricity from the distribution utility during "valley" hours, when prices charged by generation utilities are less than half of prices charted during "peak" hours. During "peak" hours, the consumers buys as much electricity as before the installation of RPV.

In consequence, reductions in revenue for the distribution utility are considerably larger than reductions in payments going out to the generators, as illustrated by Figure 8.

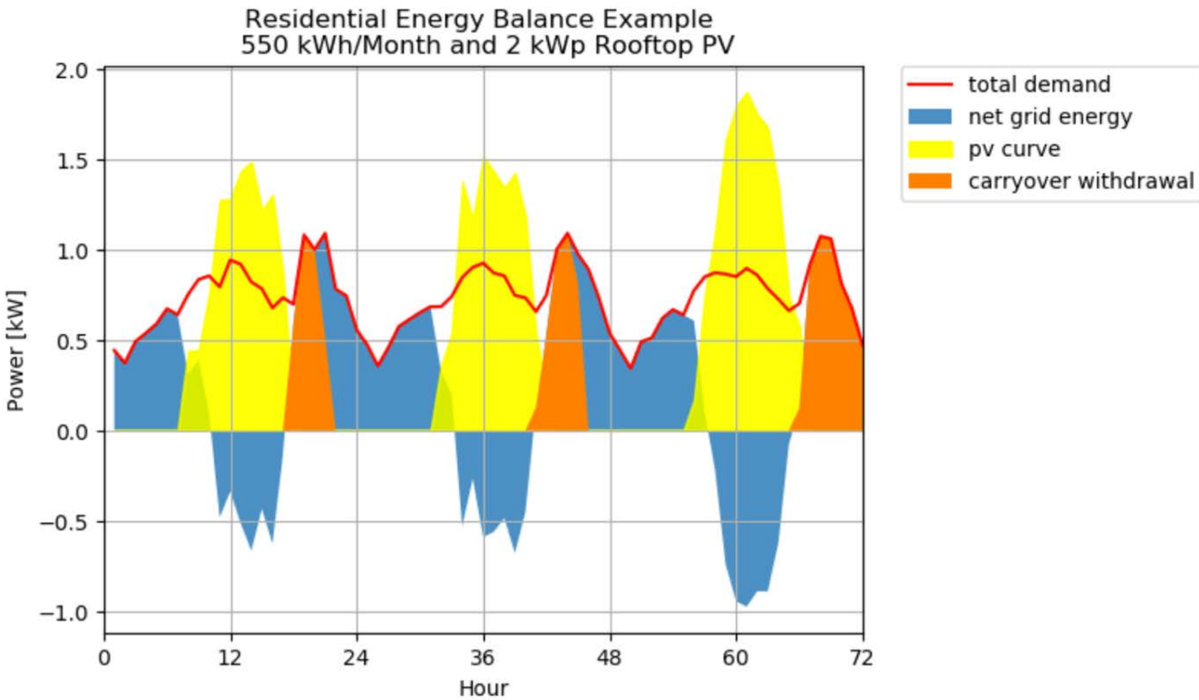
Figure 7. Net Utility Revenue Changes for Case 1



Source: Author's compilation.

Results for the distributor are even worse when the consumer is able to inject energy into the grid. Figure 9 illustrates the energy balance of a consumer with the same total energy consumption as before, but with a 2 kWp RPV installation.

Figure 8. Case 2: 550 kWh/month Residential Consumer with 2kWp

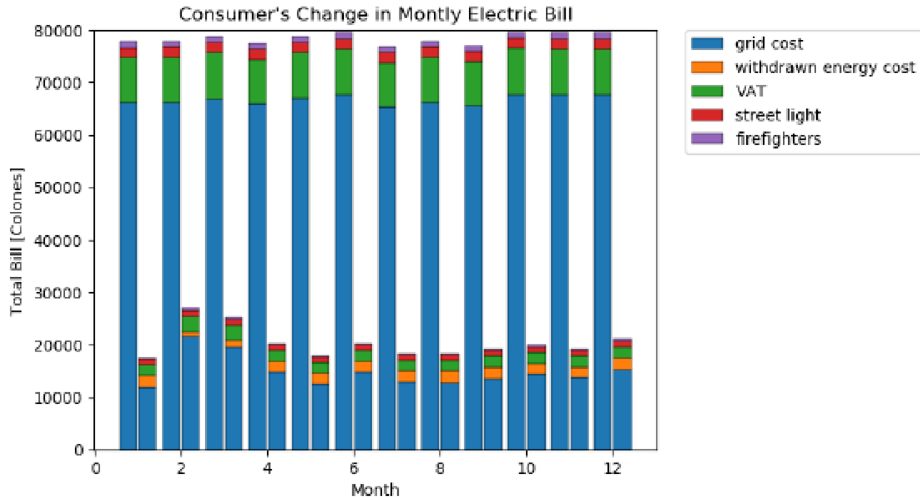


Source: Author's compilation.

Now the consumer produces more energy than it consumes during "valley" hours, injecting the surplus into the grid and "withdrawing" it during peak hours. Since the physical reality is that electricity is not stored but used instantly, what actually happens from the point of view of the distribution utility is that it buys high-priced electricity during peak hours but charges the consumer only for "withdrawal."

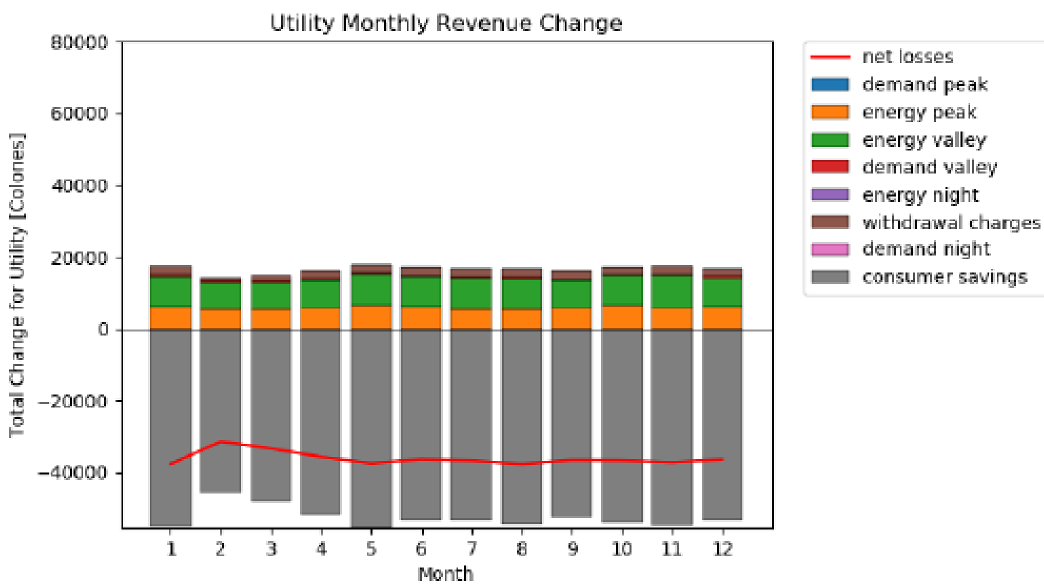
Not surprisingly, savings for the consumer and net revenue losses for the distribution utility are much larger in Case 2, as illustrated by Figure 10 and Figure 11.

Figure 9. Changes in Monthly Bill for Case 2



Source: Author's compilation.

Figure 10. Net Utility Revenue Changes for Case 2



Source: Author's compilation.

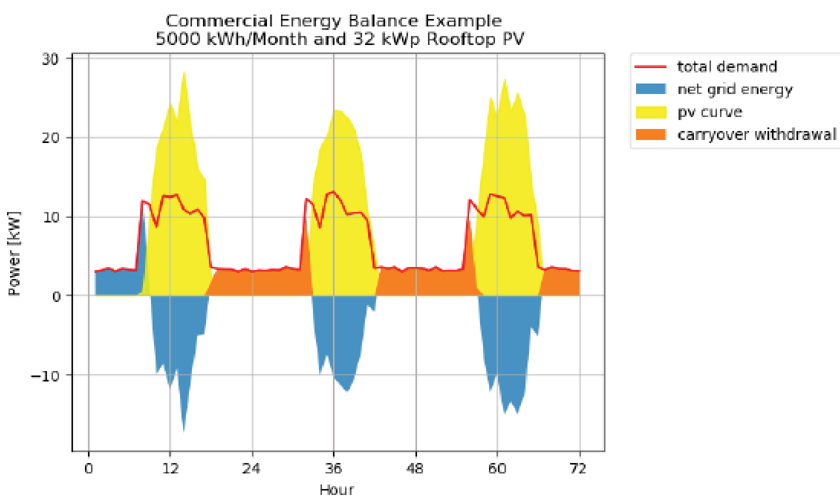
Savings for a consumer with this level of energy consumption would be even larger with a 4 kWp installation, which would generate multi-day carryovers (note that in Figure 9 energy is injected into and withdrawn from the grid within the same 24-hour period). However, we do not illustrate that case here for brevity's sake.

The two cases presented illustrate part of the procedure that will be used in the simulations included below: for each level of energy consumption and consumer type, savings for the consumer and net revenue changes for the utility are calculated for each possible RPV installation size, until the optimal size installation is determined taking into account prices of PV panels and credit terms.

6.2 Commercial-Industrial Consumer

The third case we will illustrate is that of a commercial-industrial consumer with a monthly energy demand of 5,000 kWh/month and a 32 kW RPV installation. This case will allow us to highlight a key regulatory distortion that is driving the adoption of RPV in Costa Rica. As mentioned before, residential consumers pay no demand charges. Commercial-industrial consumers, on the other hand, pay demand charges if their total demand exceeds 3,000 kWh/month. Potential monthly savings for consumers are considerable if RPV installations allow them to remain below the threshold that triggers demand charges.

Figure 11. Case 3: 5,000 kWh/month Commercial Consumer with 32 kWp



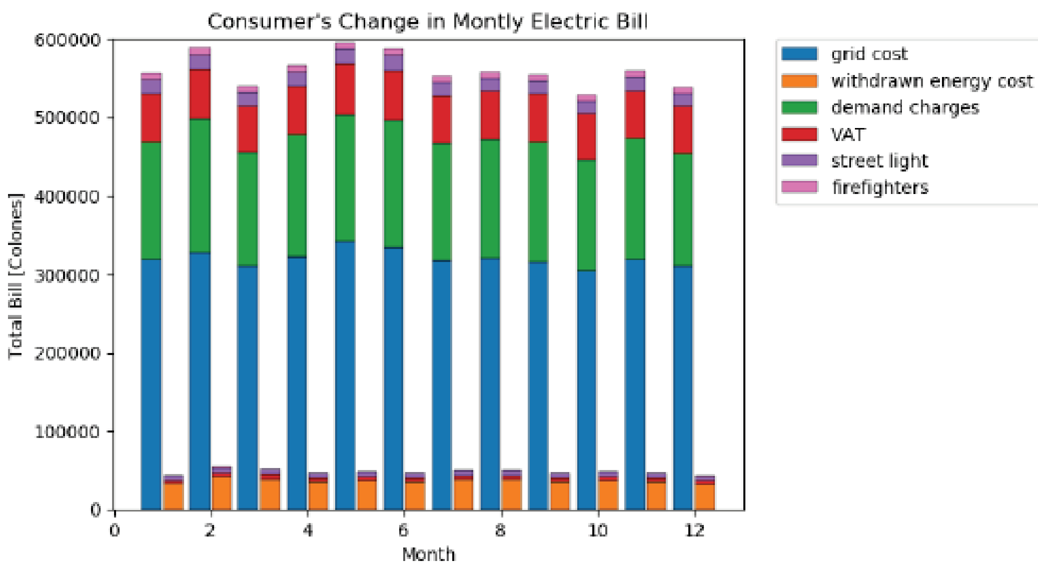
Source: Author's compilation.

Note that energy surpluses are quite high and take place during the morning and afternoon "valley" hours, as well as mid-day "peak" hours. Energy withdrawals take place during a period of more than 12 hours that includes "valley" and "evening" hours. Total withdrawals are less than

total injections, due to the regulatory norm that allows "withdrawals" only up to 49 percent of each client's total energy consumption.

The key impact, not obvious in the graph, is that for seven out of 12 months, total energy from the grid remains below the 3,000 kWh/month threshold, so that demand charges are not triggered.[8] As a result, changes in the consumer's monthly bill are quite dramatic, as illustrated by Figure 13, and so are the losses for the utility, as illustrated by Figure 14.

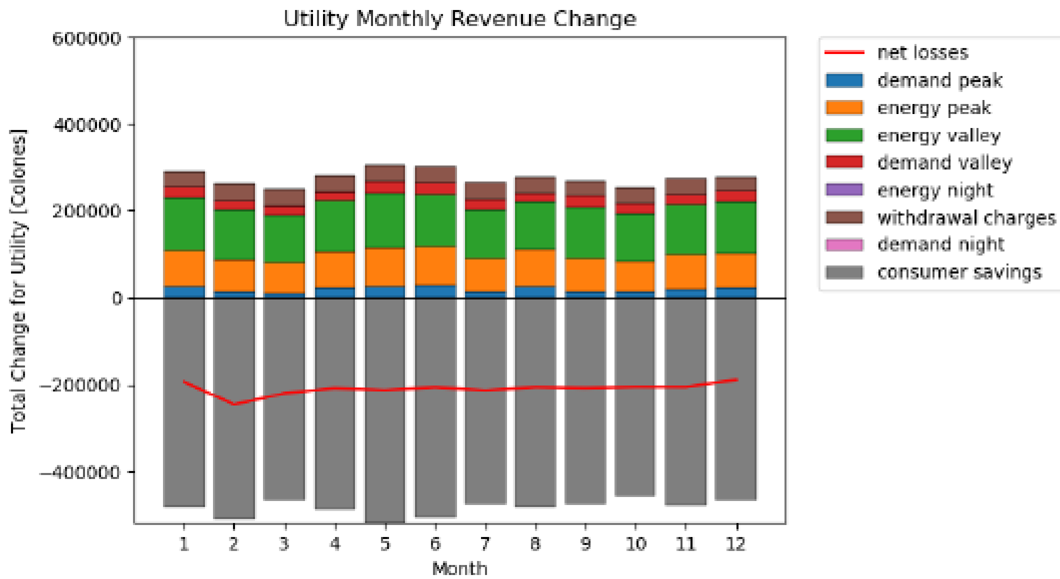
Figure 12. Changes in Monthly Bills for Case 3



Source: Author's compilation.

[8] The numbers can be verified in the Excel file provided separately upon request.

Figure 13. Net Utility Revenue Changes for Case 3

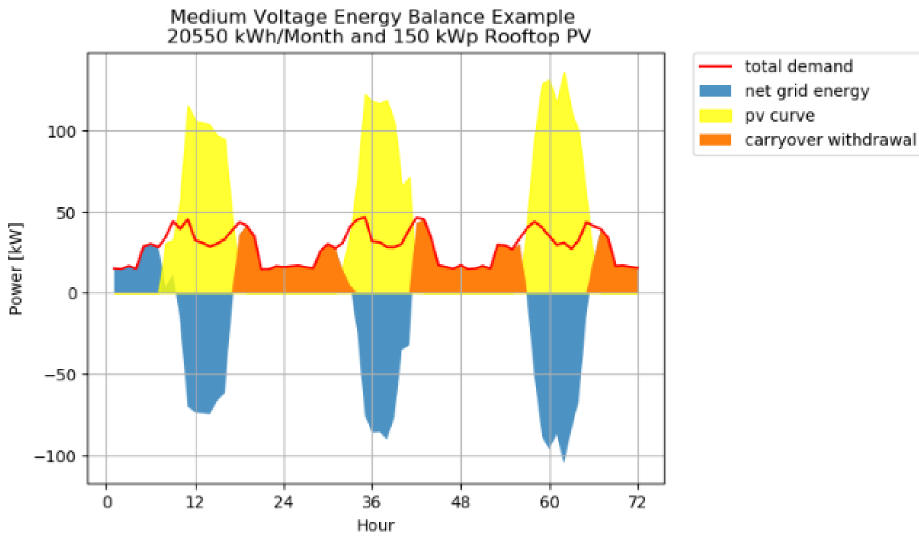


Source: Author's compilation.

6.3 TMT Consumer

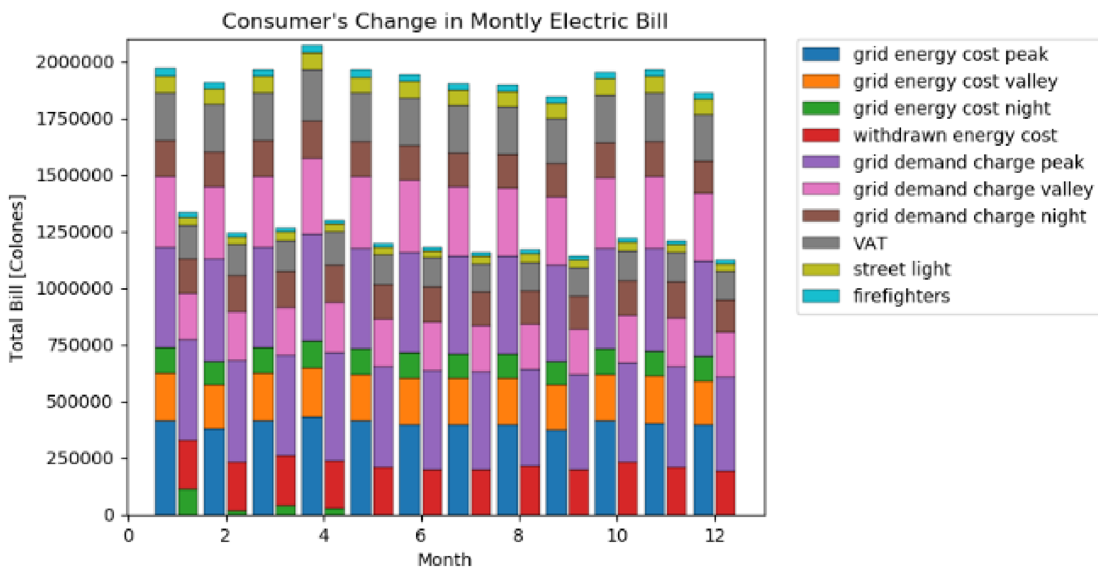
As a final illustration, Case 4 describes a 20,550 kWh/month TMT customer with a 150 kWp RPV installation. The next three figures show the customer's energy balance, the changes in monthly bills and net revenue changes for utilities. Unlike the other cases, there are large savings for the consumer while revenue changes for the utility are very small. The same results were obtained for smaller RPV installations. These results suggest that net revenue losses for the distribution utility, in the two previous cases, result directly from a non-neutral pricing structure that includes a tax-free and subsidized first consumption tranche for residential consumers (who, in addition, are charged the same price for electricity during peak, valley and evening hours, and are not charged for demand). In the case of commercial-industrial customers, demand is only charged when total monthly energy demand is above 3,000 kWh/month.

Figure 14. Case 3: TMT Consumer



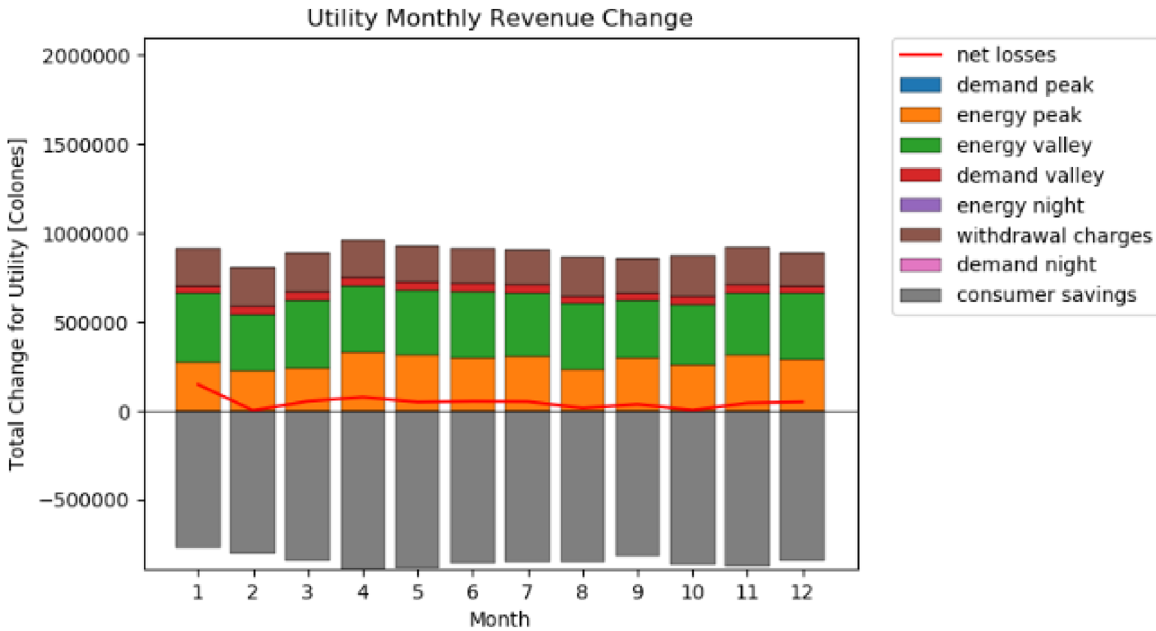
Source: Author's compilation.

Figure 15. Changes in Monthly Billings for Case 3



Source: Author's compilation.

Figure 16. Net Utility Revenue Changes for Case 3



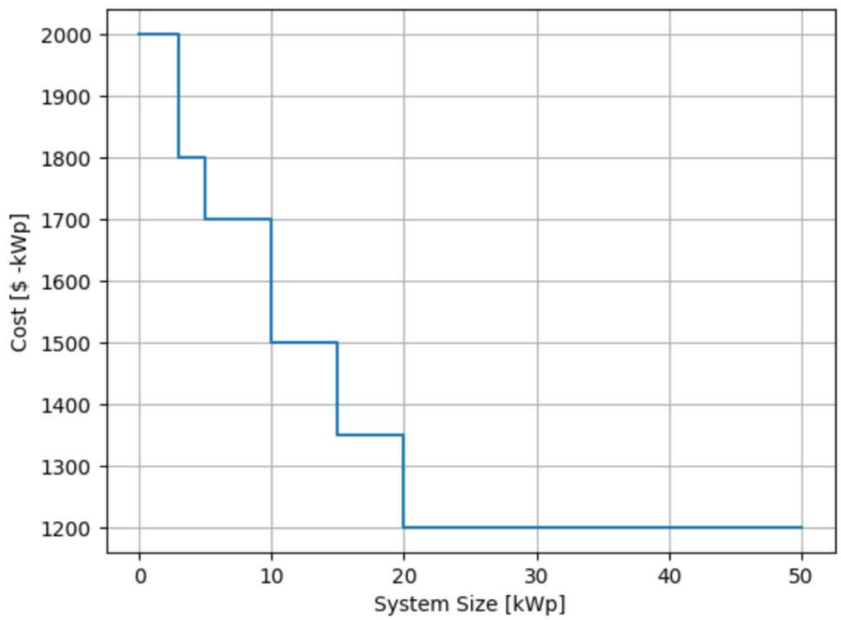
Source: Author's compilation.

7. Net Consumer's Saving over 10 Years

In Section 6 we presented some examples of consumer's savings taking into account changes in monthly electricity bills only. In this section we incorporate the cost of PV equipment and the terms under which financing is available to purchase it for residential and non-residential consumers.

The cost curve for PV systems used in this study is shown in Figure 18; the prices for small systems start at $2,000/kWp including all the fixed costs of installation. Prices are lower for larger systems given that the fixed costs are spread out and can reach $1,200/kWp.

Figure 17. PV System's Cost Curve



Source: Author's compilation.

Table 7 summarizes the relevant financial parameters for the adoption calculations.

Table 7. PV Equipment Costs and Financing Conditions

Down payment	25%
Exchange Rate	600 ₡/$
APR	8.5%
Financing term	5 years

Source: Author's compilation based on interviews with PV installers.

Note once again that what we are doing is presenting examples that illustrate the building blocks of the simulation models presented later in this paper. Given this purpose, we will present 10-year savings calculations for some residential, commercial and TMT consumers under current pricing rules.

7.1 Residential Consumers

Recall the PV adoption rule for residential consumers: they will install PV systems if total payments over a 10-year period are less than without a PV system, with the added provision that payments during the first five years (the duration of the loan required to buy the equipment) are

no larger than without the system. In other words, consumers that could save over 10 years, but whose billings increase during the first five, are assumed to decide not to install a PV system.

Under these assumptions, no consumers below the 300 kWh/month threshold will install PV systems. Consumers in the 300 to 2000 kWh/month range will install PV systems (of different sizes, as will be shown below), and consumers at or above the 2,500 kWh/month range will not install PV systems.

Figure 18. Five-Year Net Present Value for Residential Consumers

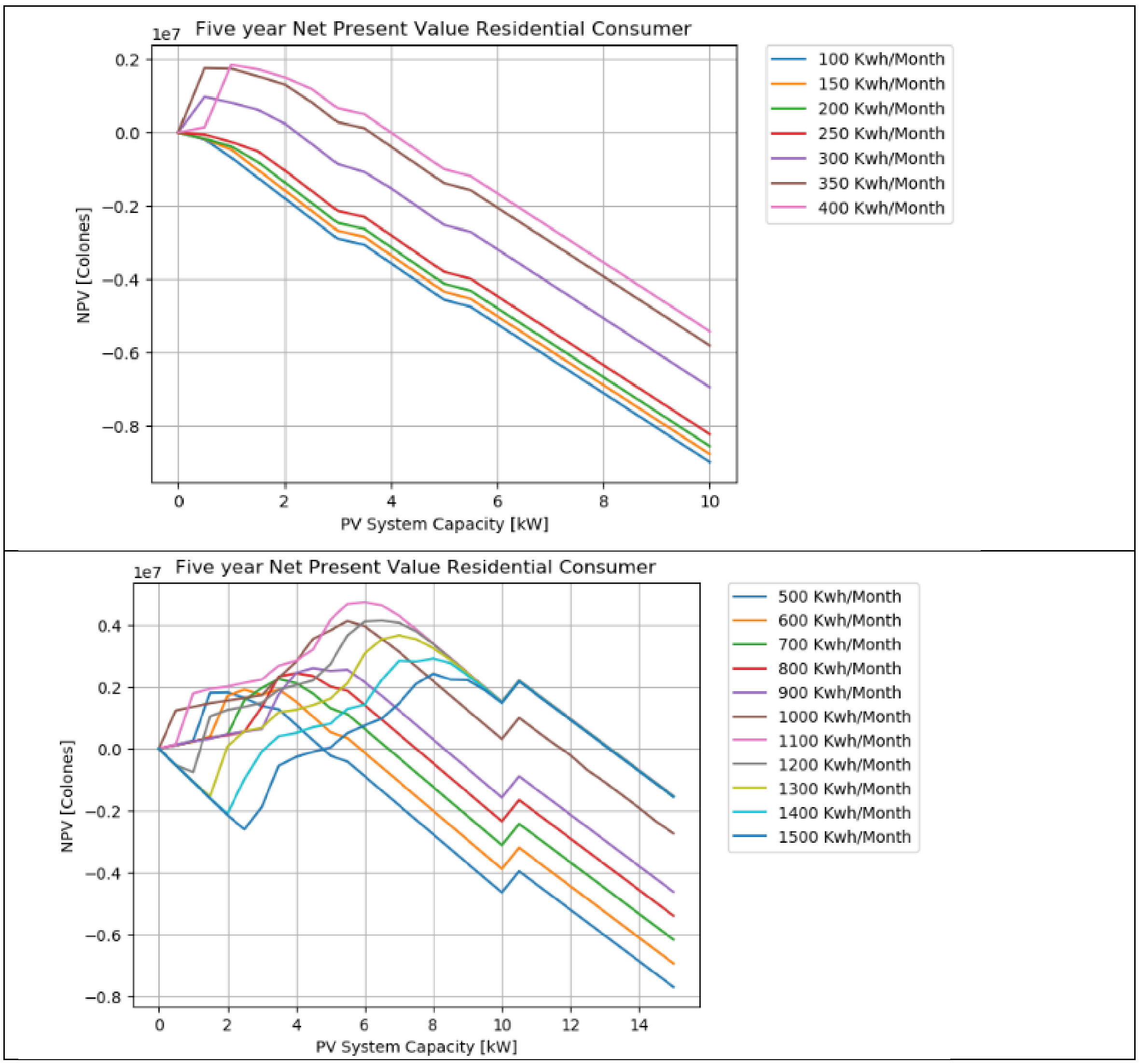
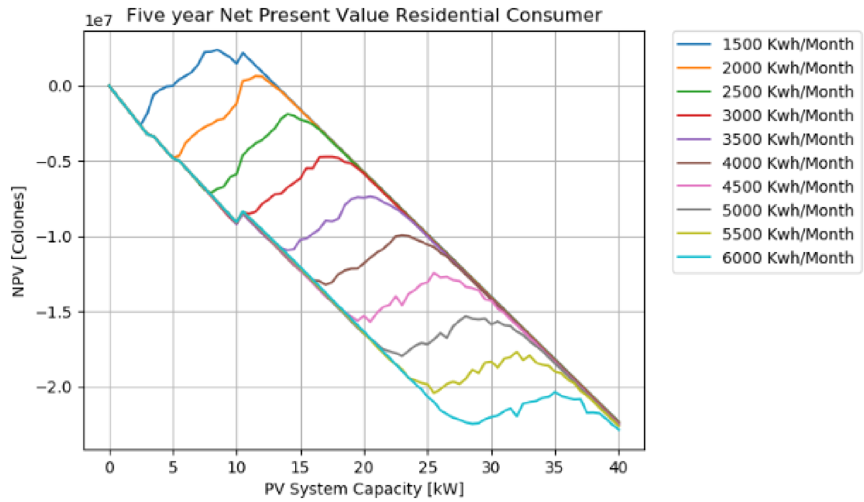


Figure 19., continued



Source: Author's compilation.

If the first condition is met (positive five-year net present value of the investment, which in this case is tantamount to savings during the first five years), the size of the PV system to be installed will be the one that renders the largest average monthly savings over 10 years.

Figure 20. Average Monthly Savings for Residential Consumers

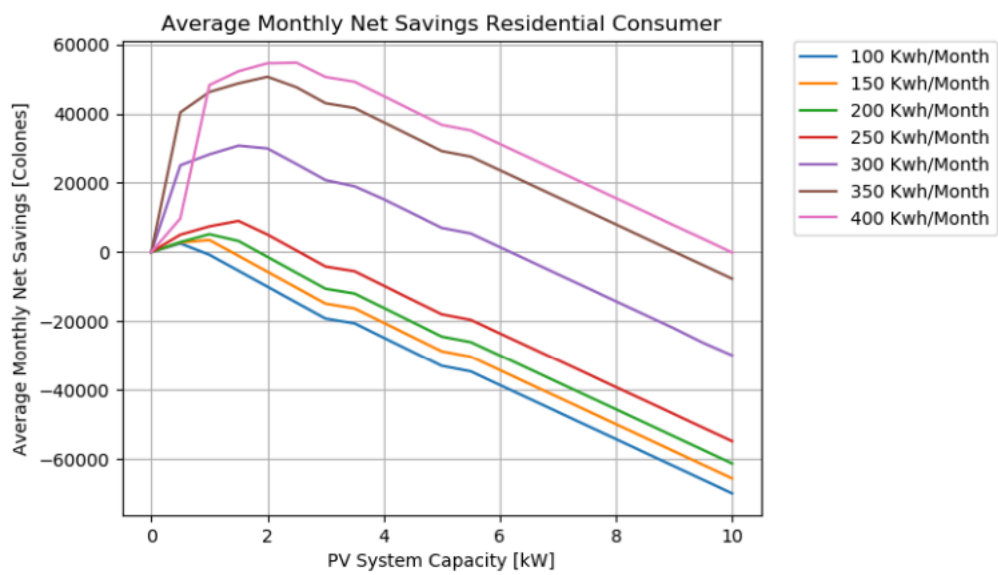
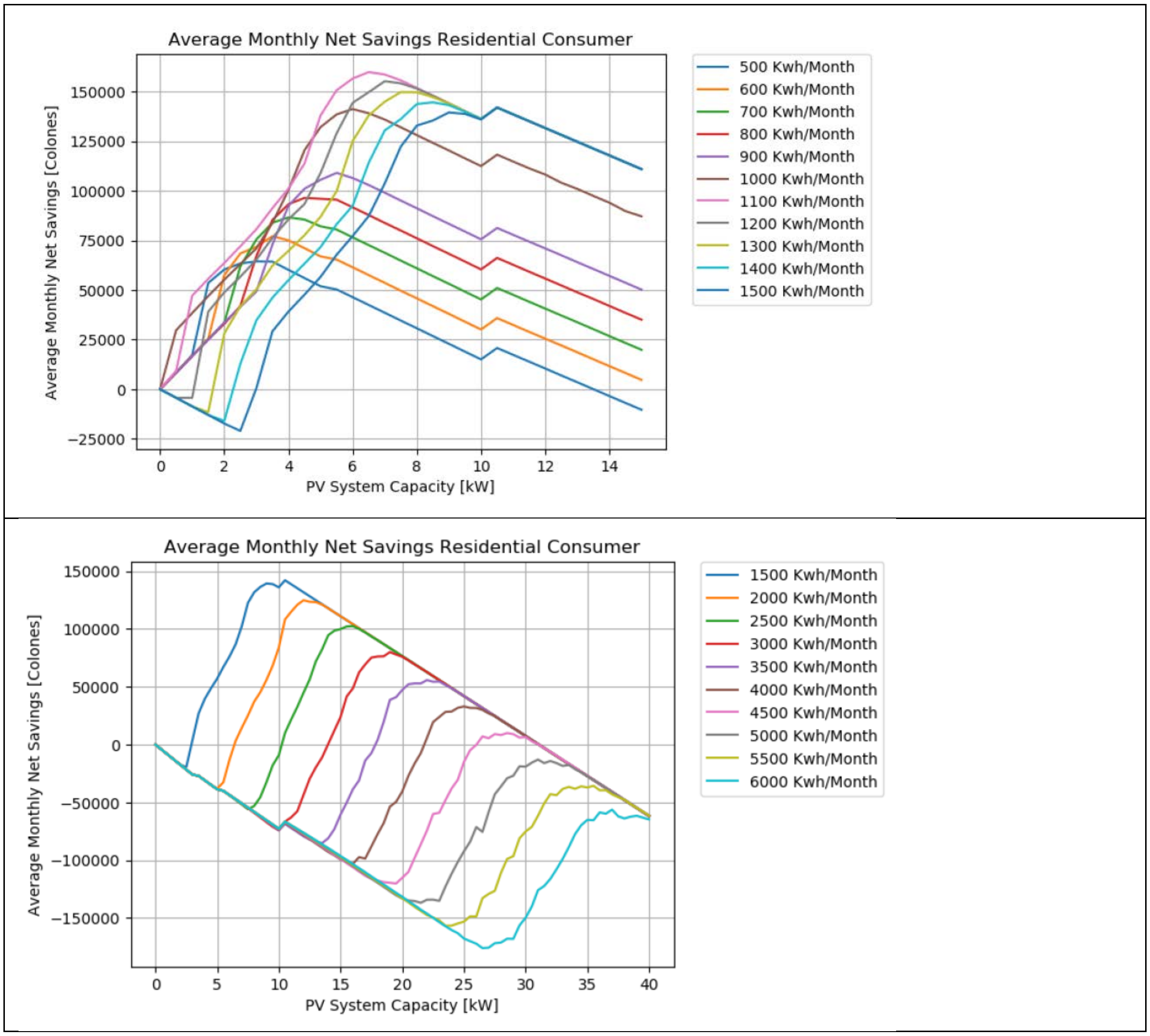


Figure 21., continued

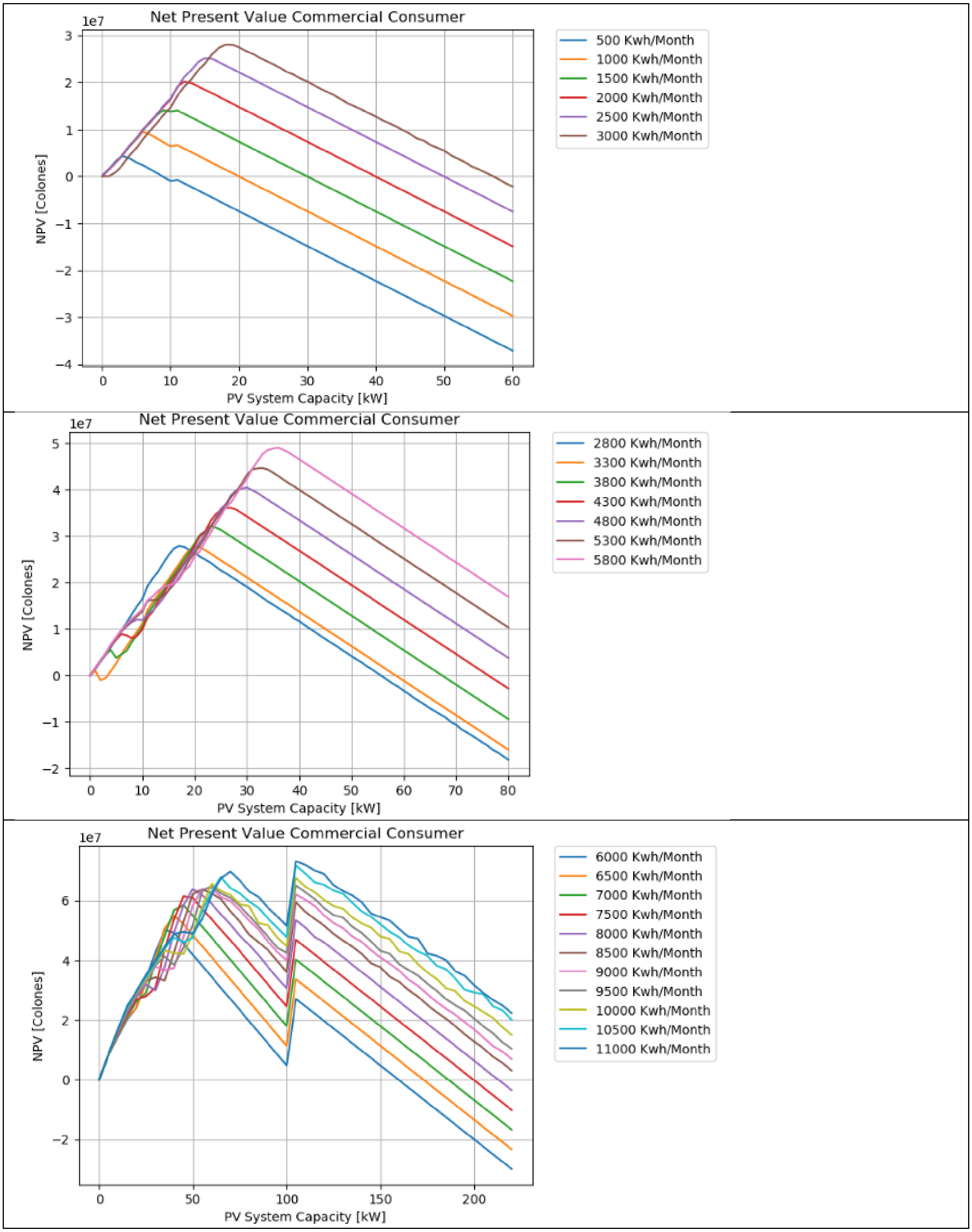


Source: Author's compilation.

7.2 Commercial-Industrial Consumers

In this case we assume that consumers take into account the down payment and discount future cash flows at an internal rate of 6 percent. Unlike residential consumers, some of which did not benefit from an RPV installation, there is some size of installation that maximizes the net present value of the investment for all commercial-industrial consumers, as shown in the three panes of Figure 21.

Figure 22. Net Present Value of RPV Investment for Commercial-Industrial Consumers



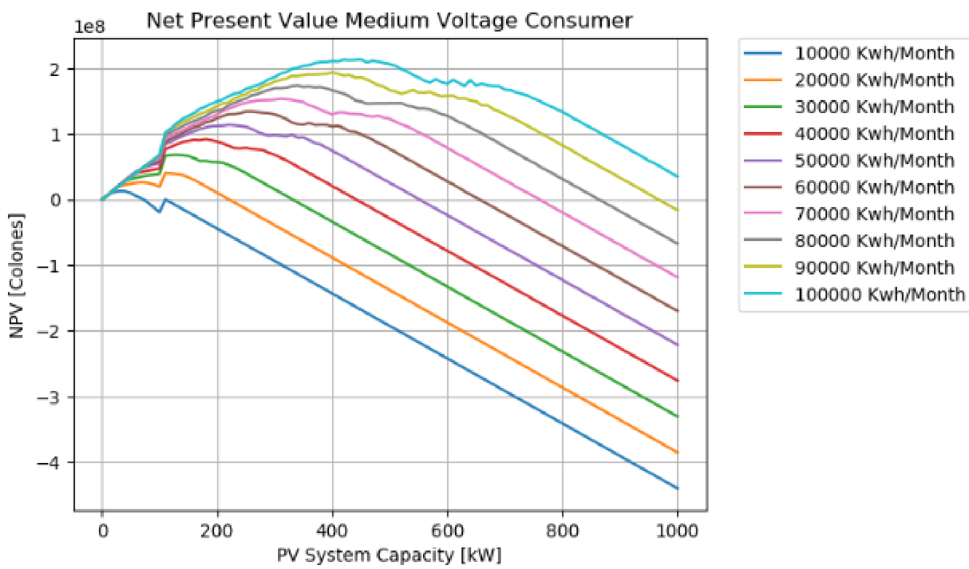
Source: Author's compilation.

Note that for consumers in the third panel there are two local maxima, and that for consumers at or above the 10,000 KWh/month, the maximum-maximorum is for installations of more than 100 kpW. Since consumers in this range should be moved to the TMT tariff, we will assume that they opt for the smaller RPV installation.

7.3 TMT Consumers

Under the same assumptions as in the previous case, there are certain size installations that maximizes the NPV of the RPV installation for al TMT consumers, which increases as total energy consumption increases.

Figure 23. NVP of RPV Investment for TMT Consumers



Source: Author's compilation.

8. Impact of "Neutral" Pricing Rules

All the examples developed so far have been developed assuming current pricing rules, which have the characteristics listed below.

- The rules include a subsidized and tax-free tranche for residential consumers, who are charged for energy at the same price during the whole day and not for "demand" (power).

- Commercial-industrial customers are charged for demand only if their monthly energy consumption is above 3,000 kW/h.
- Both commercial and TMT customers are charged for energy at different prices during “peak,” “valley” and “evening” hours.

A neutral pricing scheme would charge all customers for energy at the same price for each time segment and would charge for demand as it is used, making no distinctions between consumer types and with no minimum total energy consumption. Lastly, a neutral scheme would apply the same taxes to all consumers.

In a later section we show the impact of “current” versus “neutral” pricing rules on RPV adoption rates, consumers’ savings and utility’s revenues. We illustrate how billings change from one set of rules to the other, with and without RPV installations.

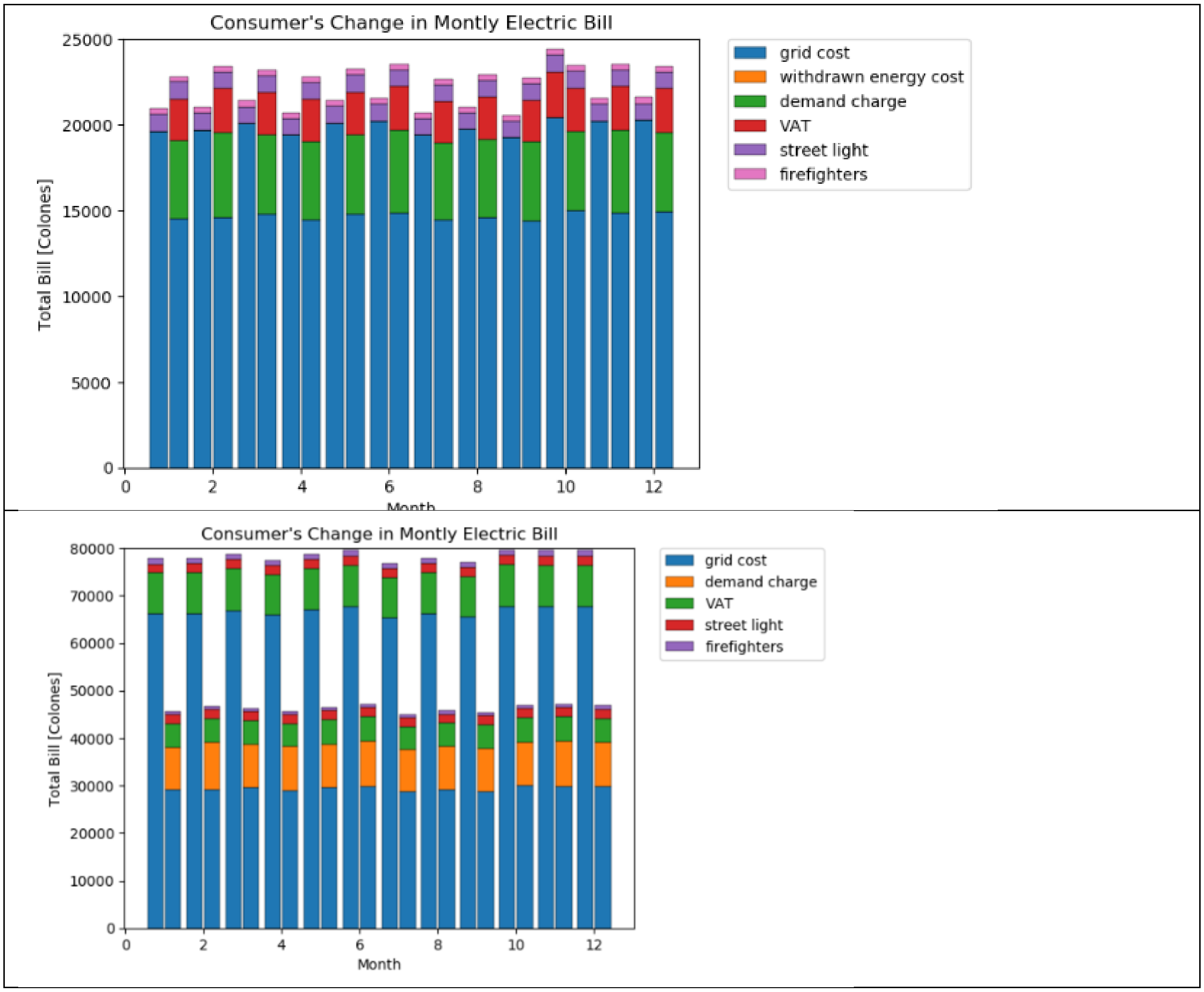
8.1 Residential Consumers

The key changes in “neutral” pricing rules are the following:

- A small increase in monthly bills for “small” consumers (275 kWh/month), who lose their subsidies and are charged for demand.
- A considerable decrease in monthly bills for large consumers (550 kWh/month), due to reduced energy charges.

These changes are illustrated by Figure 23, with small consumers in the top panel and large consumers in the lower panel.

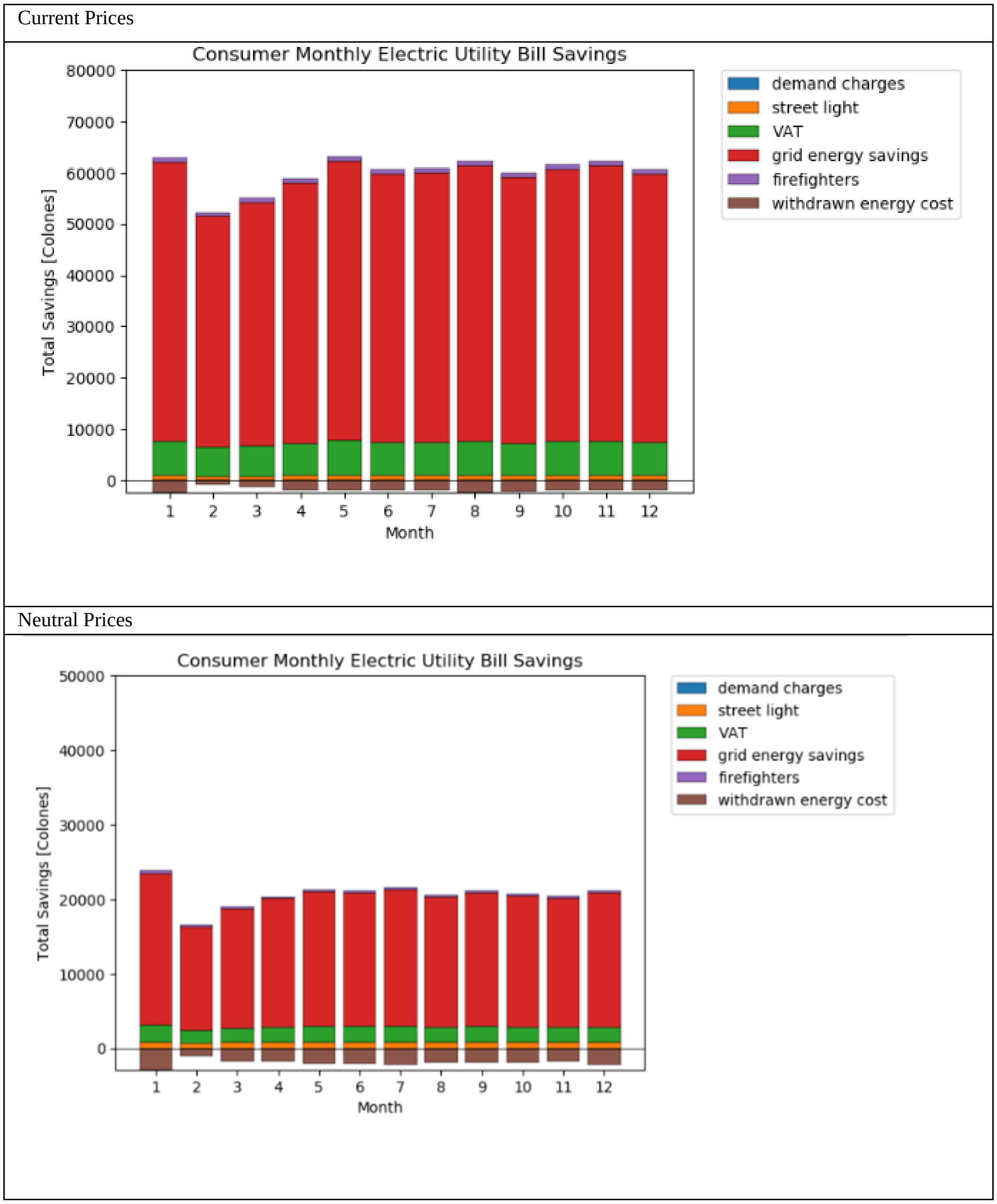
Figure 24. Changes in Residential Consumer Bills under Neutral Pricing



Source: Author's compilation.

Large residential consumers still see their monthly bills reduced with a 2 kW PV system, but the savings are smaller under neutral pricing rules, as illustrated by Figure 24. Savings under current rules is in the top panel, and savings under neutral pricing are in the bottom panel. Note that the vertical scale is not the same in both graphs. Under current rules, average savings are above ₡50,000 a month, while under neutral pricing rules they are approximately ₡20,000.

Figure 25. Comparison of Large Residential Consumer Savings

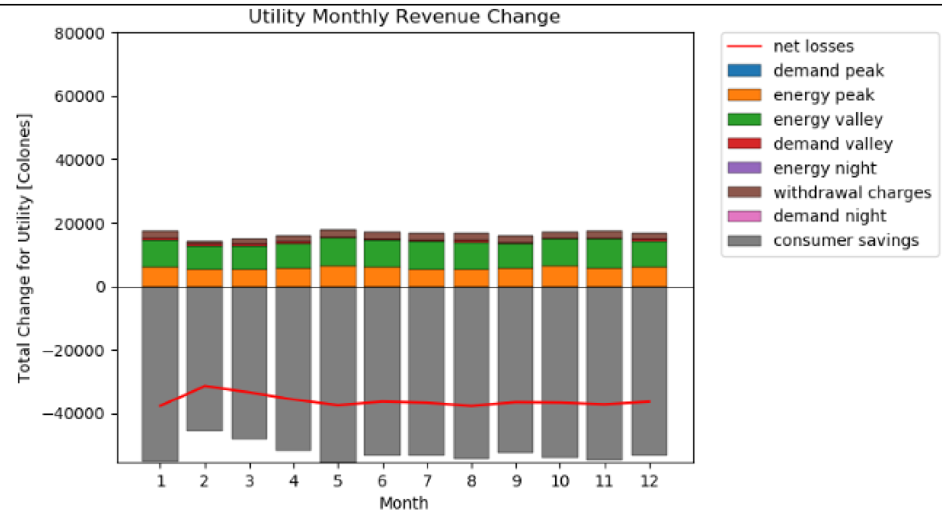


Source: Author's compilation.

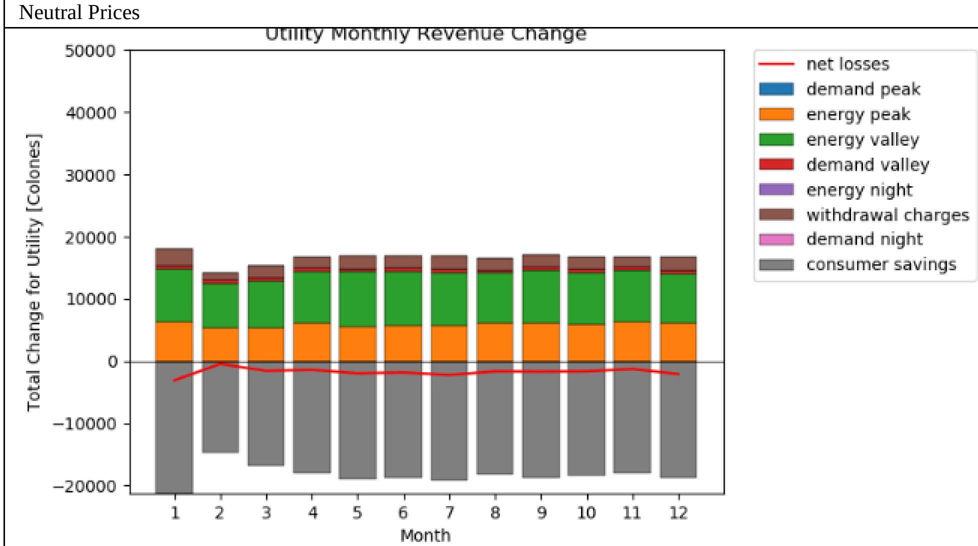
The more important result, however, concerns changes in distribution utility's revenues: under current rules, PV adoption entails large net revenue losses for the distribution utility. Under neutral pricing rules revenue losses are minimal, as illustrated by Figure 25, where, once again, the top panel corresponds to current and the bottom panel to neutral pricing rules.

Figure 26. Comparison of Revenue Losses, Residential Consumer Case

Current Prices



Neutral Prices



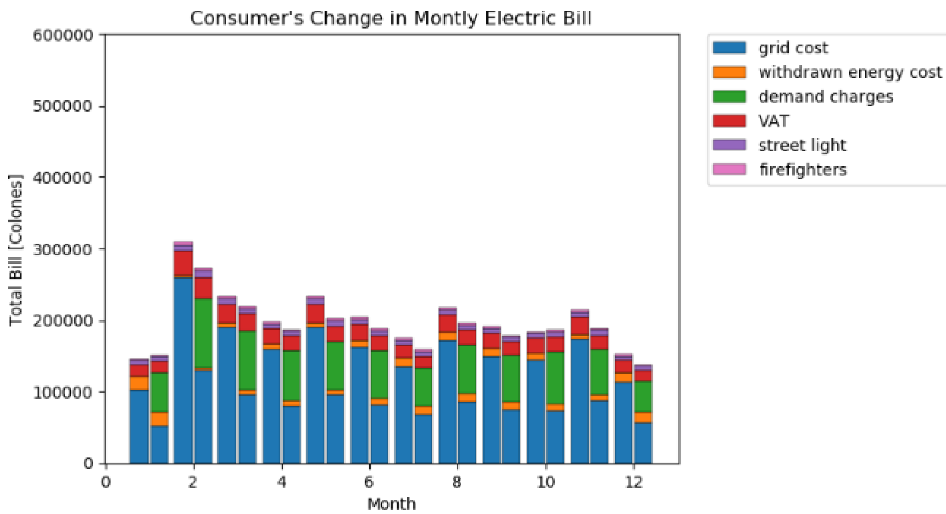
Source: Author's compilation.

8.2 Commercial-Industrial Consumers

For commercial-industrial consumers the changes resemble those observed for large residential consumers.

The first is a reduction in monthly bills without PV installation, as shown in Figure 26.

Figure 27. Changes in Commercial-Industrial Bills under Neutral Pricing



Source: Author's compilation.

A second change is smaller but still important savings with a PV installation, as shown in Figure 27.

Figure 27. Comparison of Commercial-Industrial Savings

Current Prices

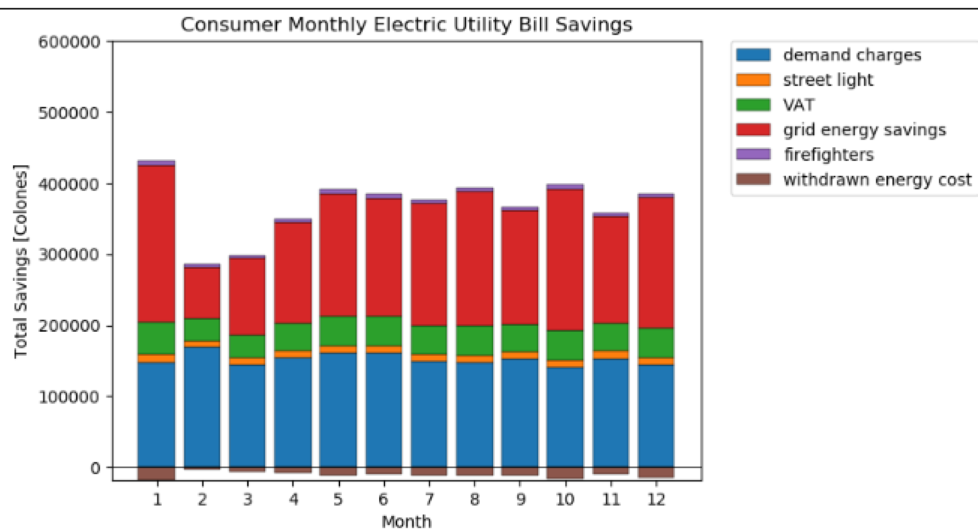
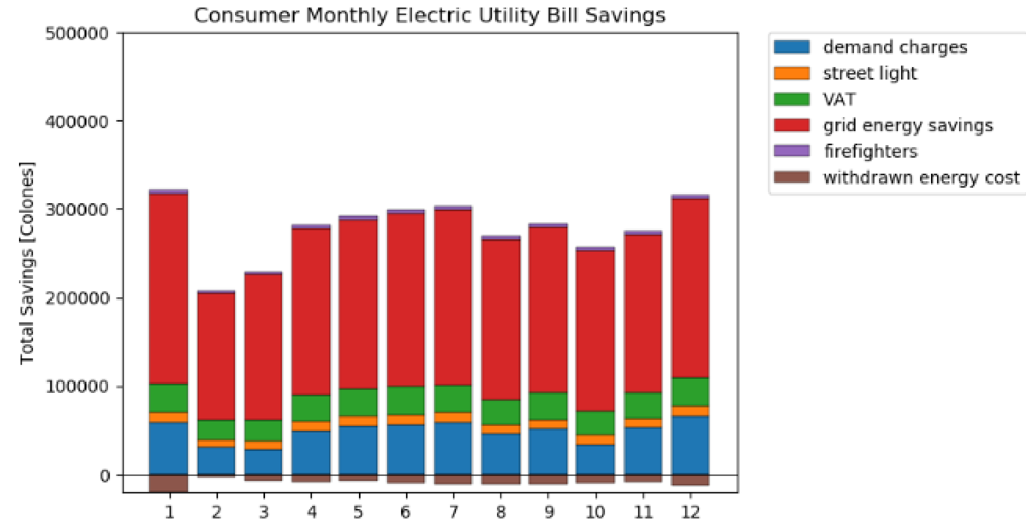


Figure 27., continued

Neutral Prices



Source: Author's compilation.

The third change is a small impact on the distribution utility's revenues, illustrated in Figure 28.

Figure 28. Comparison of Revenue Losses, Commercial-Industrial Case

Current Prices

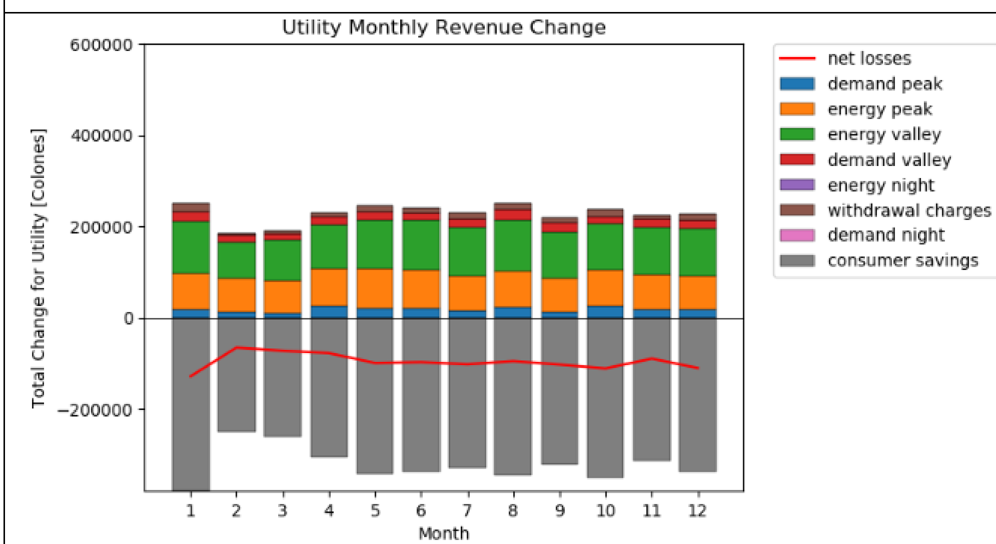
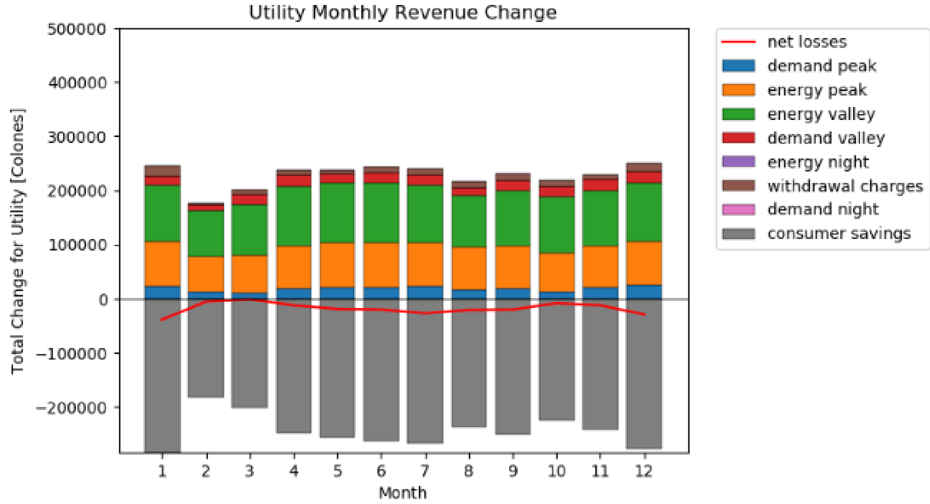


Figure 29., continued

Neutral Prices

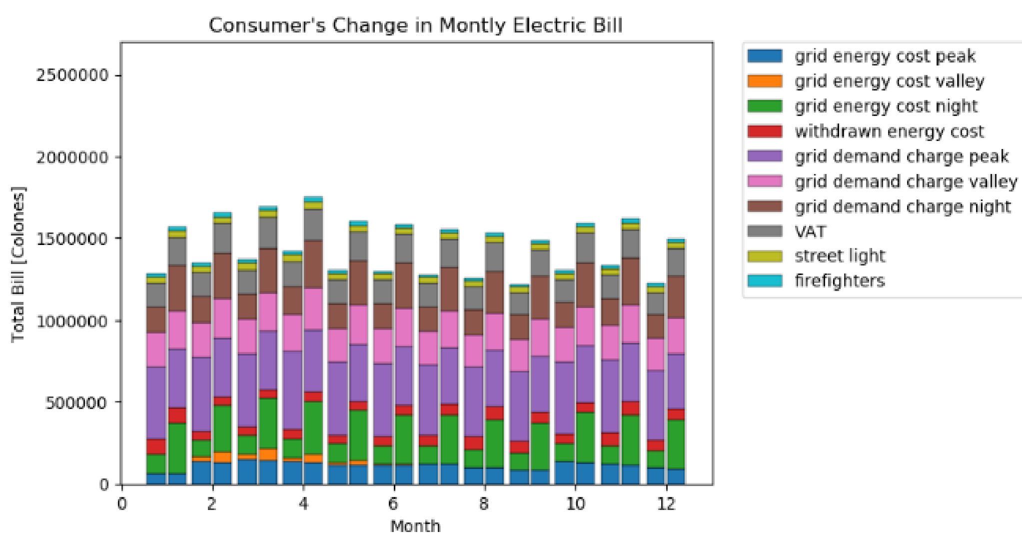


Source: Author's compilation.

8.3 TMT Consumers

Things look quite different for TMT consumers: billings go up considerably without RPV, savings from RPV are larger under neutral pricing, and the effect on the utility becomes negative (it is positive under current pricing).

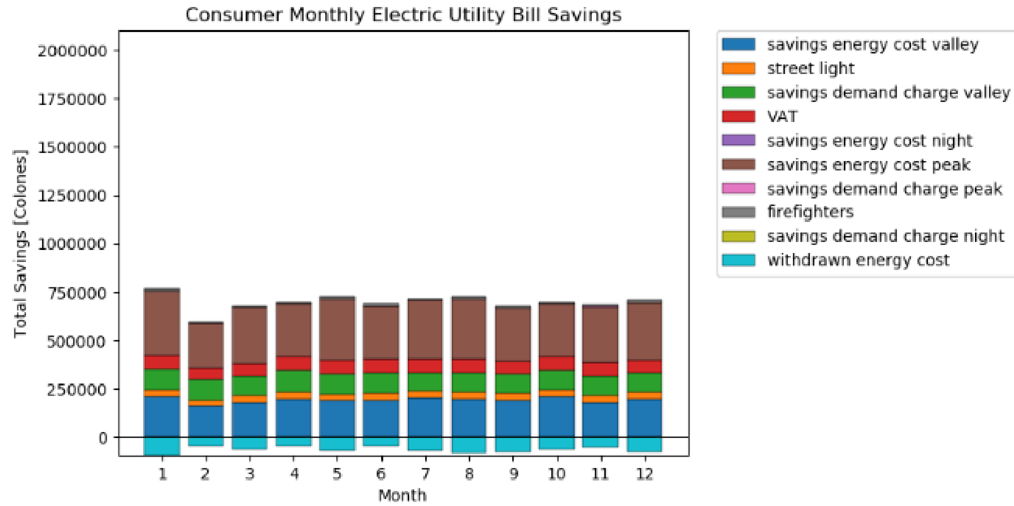
Figure 30. Changes in TMT Bills under Neutral Pricing



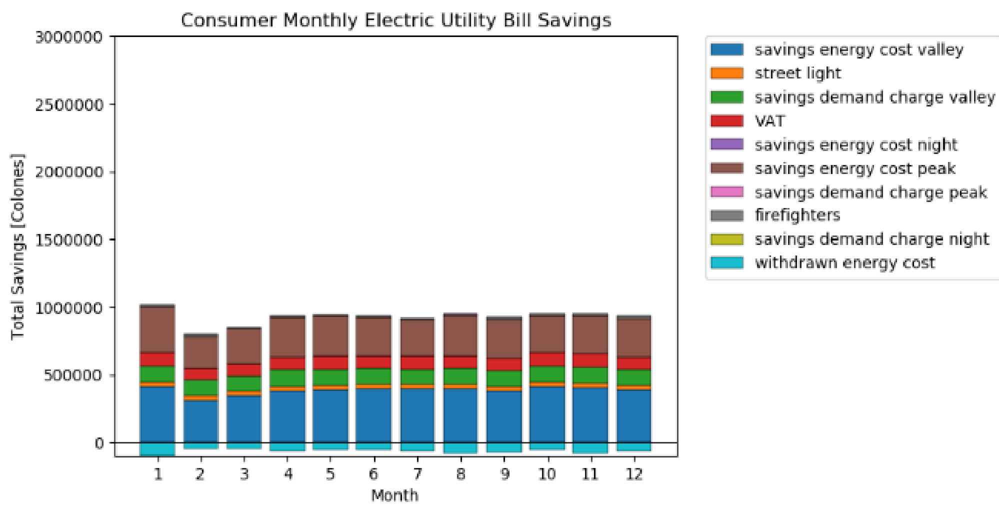
Source: Author's compilation.

Figure 31. Comparison of TMT Savings

Current Prices



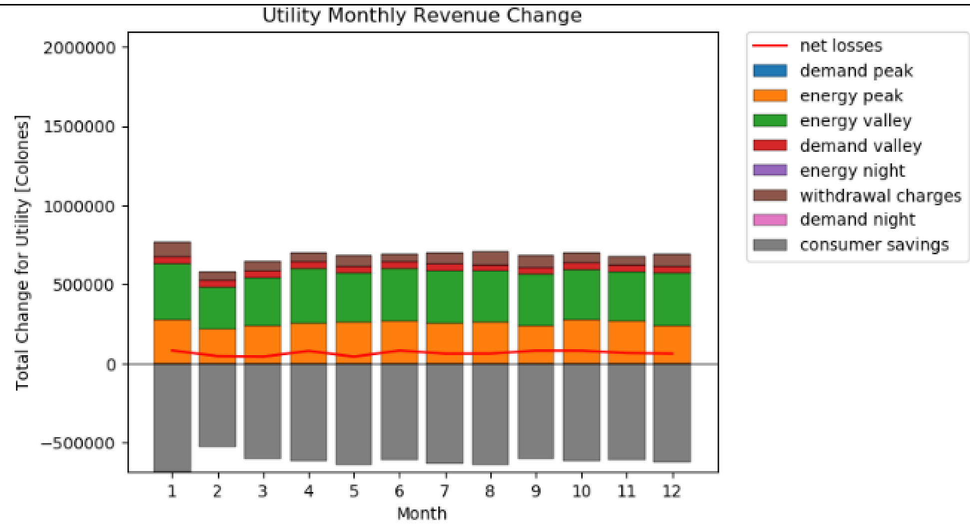
Neutral Prices



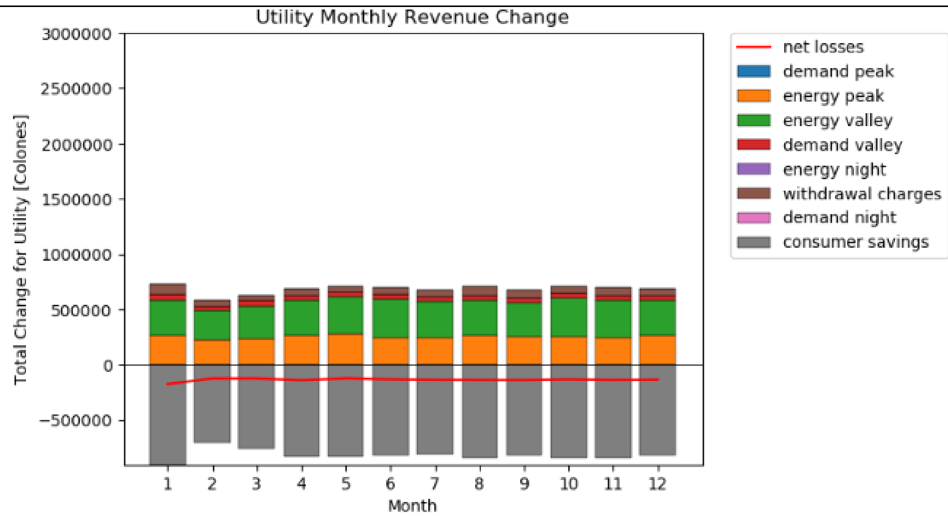
Source: Author’s compilation.

Figure 32. Comparison of Revenue Losses, TMT

Current Prices



Neutral Prices



Source: Author's compilation.

9. Optimal PV Installation and Impact on Utility's Revenues

We have so far included cases of certain consumers of different sizes and types and illustrated the changes in the energy balance and the monthly bills of those consumers under current and under neutral pricing rules. Furthermore, we calculated 10-year savings for consumers and impact on distribution utility revenues for a few illustrative cases.

In this section we take the next step: for each consumer size (in 1 kWh/month increments) and type (consumer, commercial, TMT) we calculate savings for each possible RPV installation size and select the one that maximizes consumer's savings under current and neutral pricing rules. The presentation of results is quite compact, but the graphs in this section represent the most computationally intensive step in our exercise.

9.1 Residential Consumers

The most striking result is for residential consumers. Under current pricing, very small and very large residential consumers have no incentive to install RPV systems. Consumers in between maximize savings by installing systems that, for the most part, increase with total energy consumption. However, this is all an artifact produced by current pricing rules. Under neutral rules, residential consumers have no incentive to install RPV equipment.

Figure 33. Optimal System Choice for Residential Consumers

Current Prices

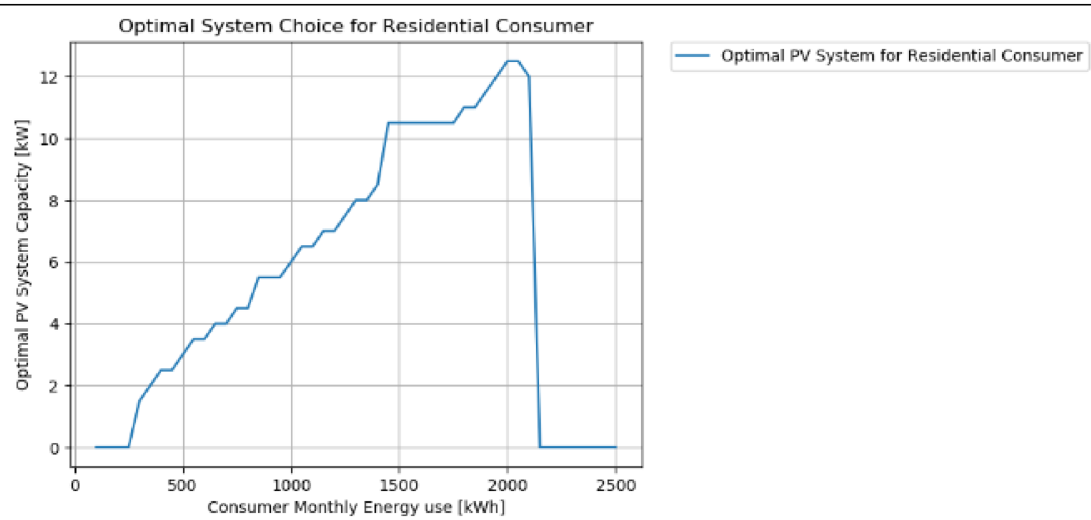
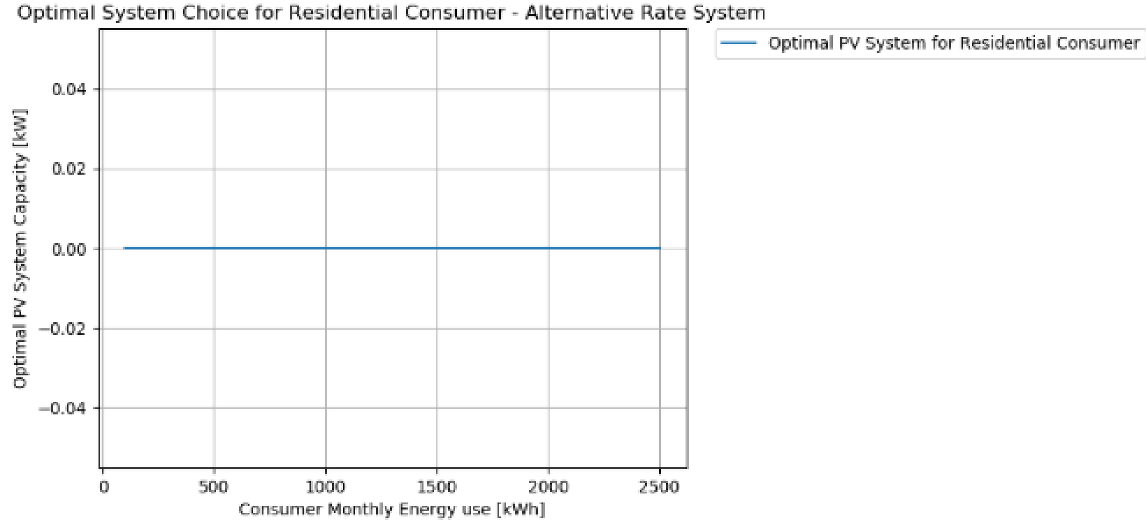


Figure 34., continued

Neutral Prices

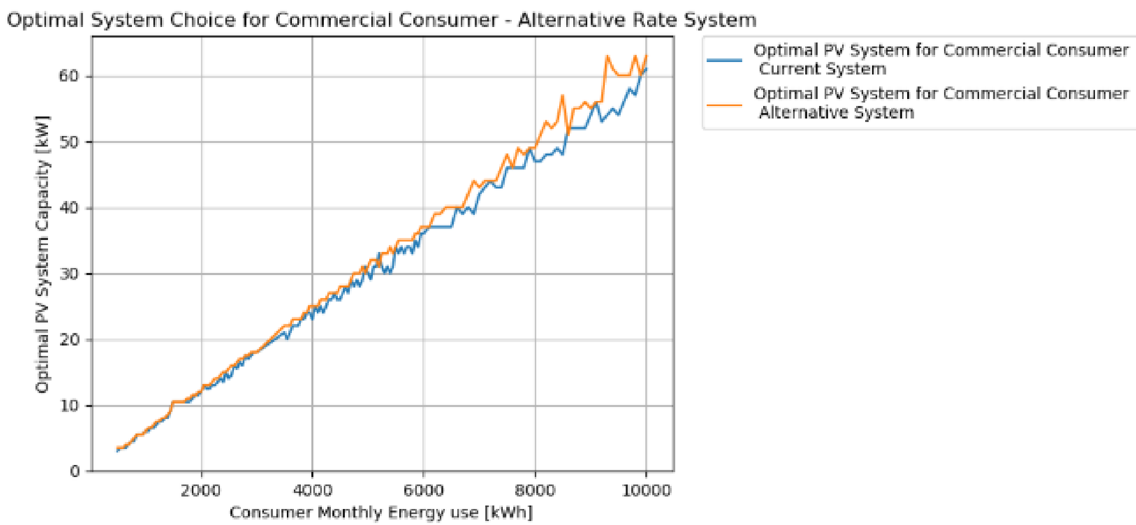


Source: Author's compilation.

9.2 Commercial-Industrial

In the case of commercial-industrial consumers, the shift to neutral pricing diminishes the optimal RPV installation size, but only modestly:

Figure 35. Optimal System Choice for Commercial Consumers

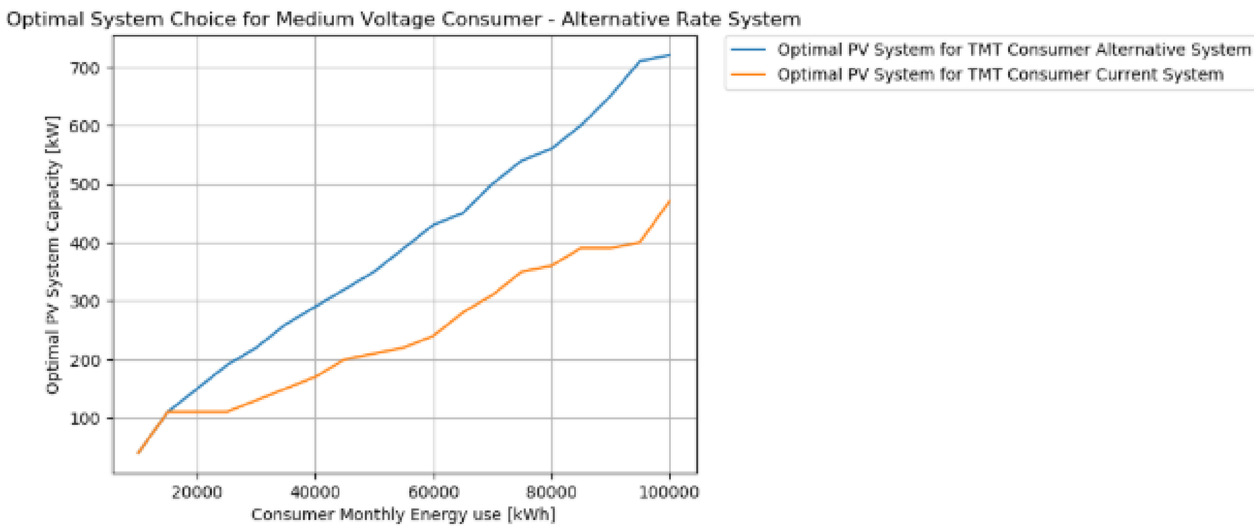


Source: Author's compilation.

9.3 TMT

In the case of TMT consumers, the optimal installation size diminishes quite sharply under neutral pricing.

Figure 36. Optimal System Choice for TMT Consumers

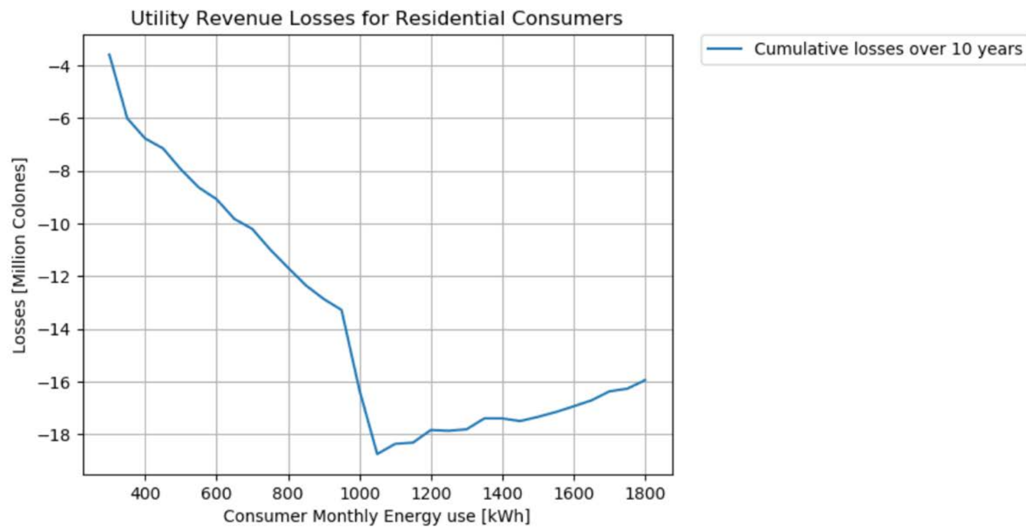


Source: Author's compilation.

9.4 Impact on Utilities: Calculation Procedure

We compute the impact on utility's revenues in three steps. First, we compute the losses associated with optimal RPV adoption for each individual consumer size in each consumer class. The results for residential consumers are illustrated in Figure 35.

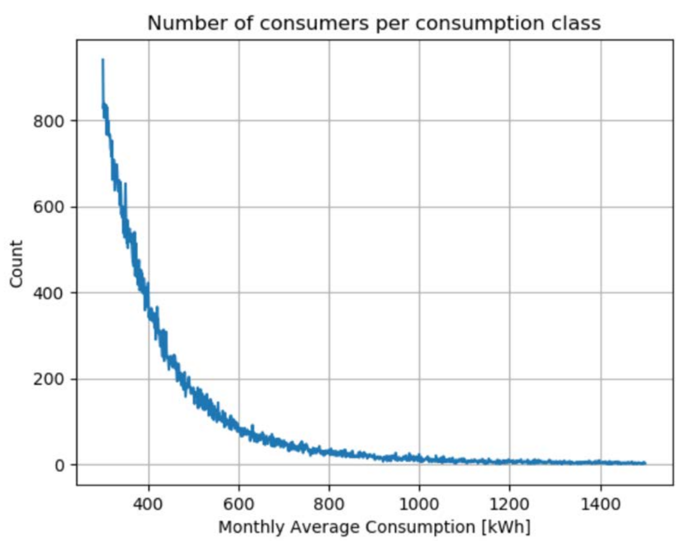
Figure 37. Utility Revenue Losses by Each Residential Consumer Size



Source: Author’s compilation.

Next, we take note of the number of consumers of each 1 kWh size:

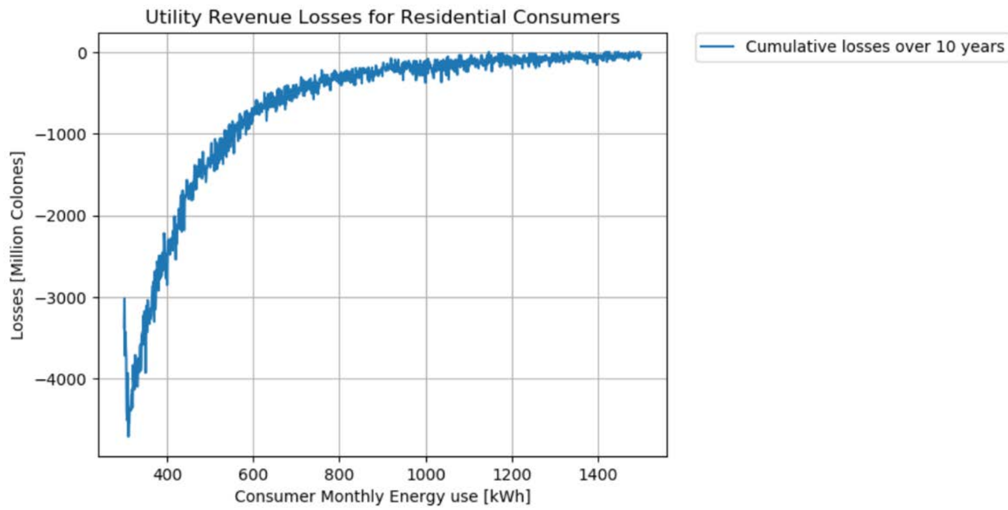
Figure 38. Number of Consumers per Consumption Size



Source: Author’s compilation.

With these two pieces of information we can compute total revenue losses for the distribution utility.

Figure 39. Utility Revenue Losses from Residential Consumers

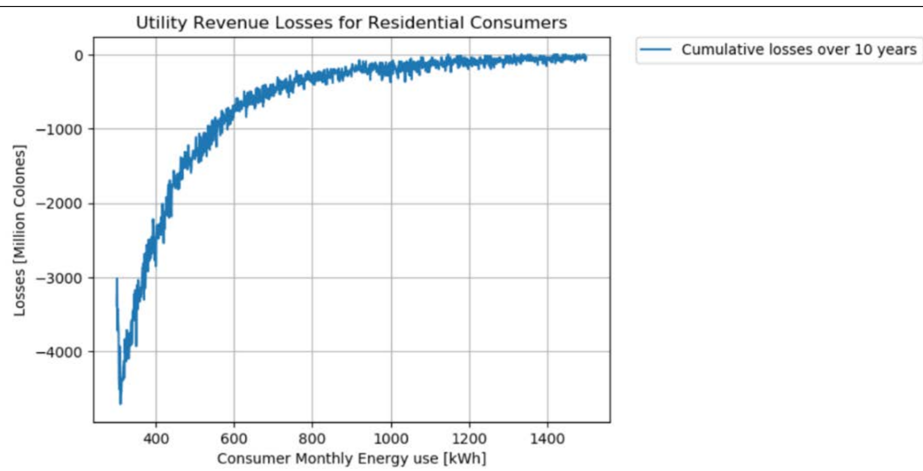


Source: Author's compilation.

The same exercise is performed for commercial and TMT consumers, first under current pricing and then after neutral prices. The results are presented next.

9.5 Impact on Utilities: Results

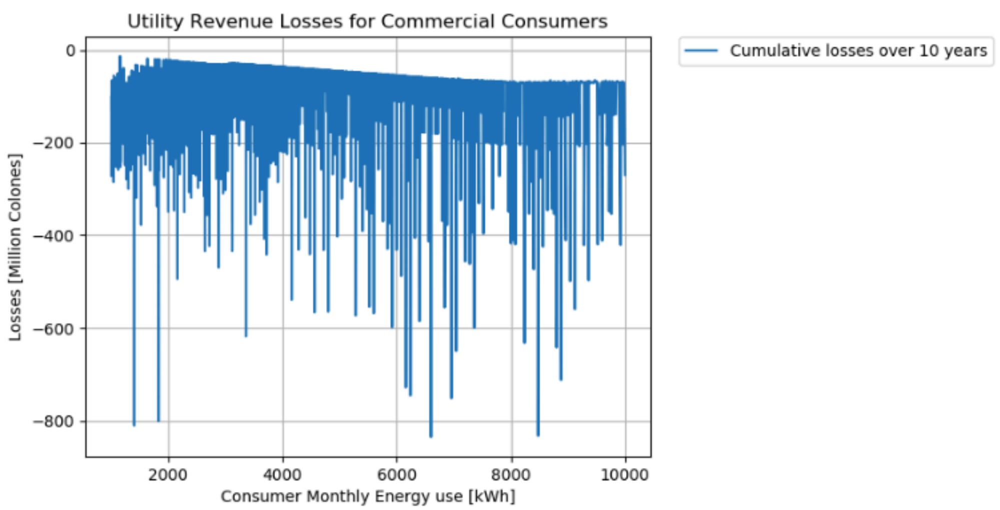
Figure 40. Residential Consumer-Induced Revenue Changes under Current and Neutral Pricing

Current

CR 813,628 million
Neutral
No adoption, hence no revenue loss
0

Source: Author's compilation.

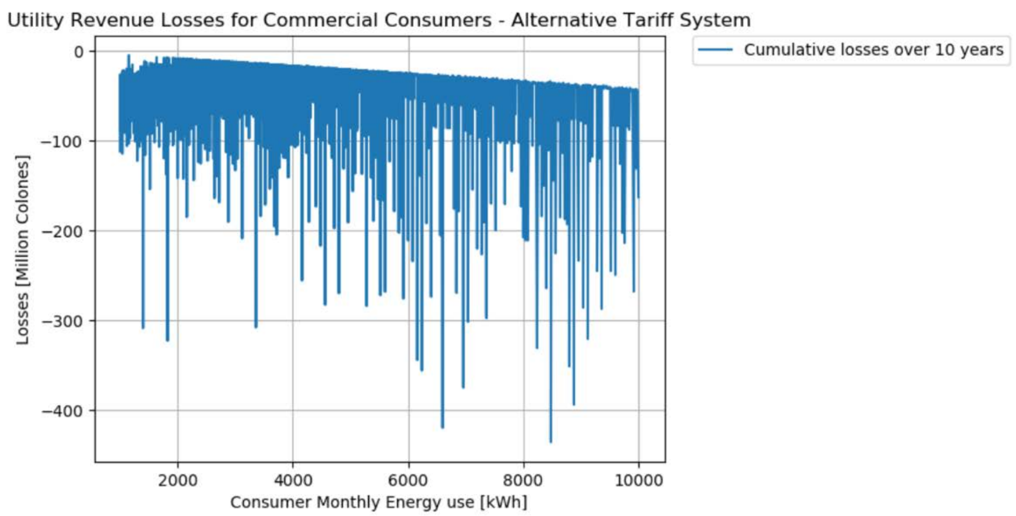
Figure 41. Commercial Consumer-Induced Revenue Changes under Current and Neutral Pricing

Current



CR 409,181 million

Neutral

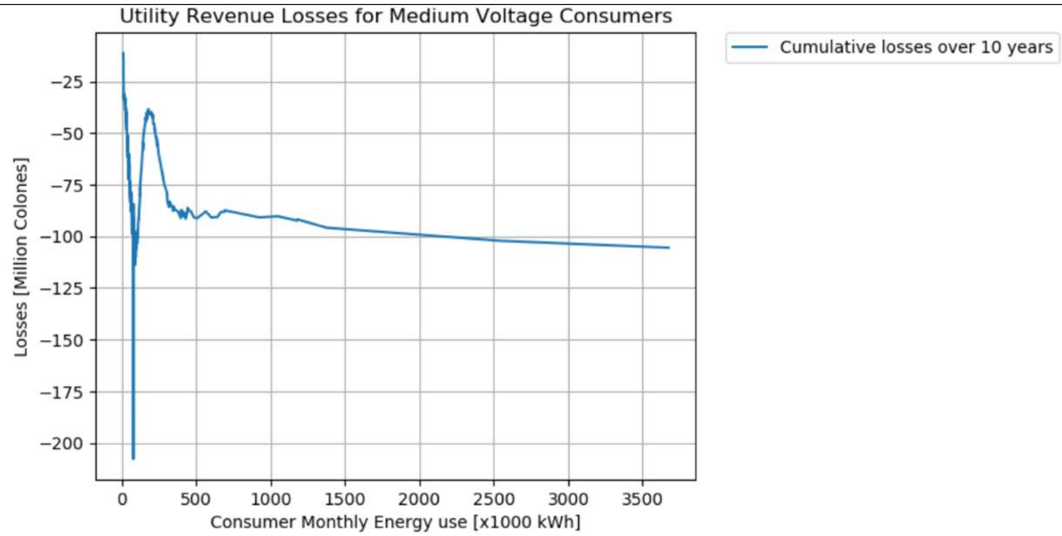


CR 182,043 million

Source: Author's compilation.

Figure 42. TMT Consumer-Induced Revenue Changes under Current and Neutral Pricing

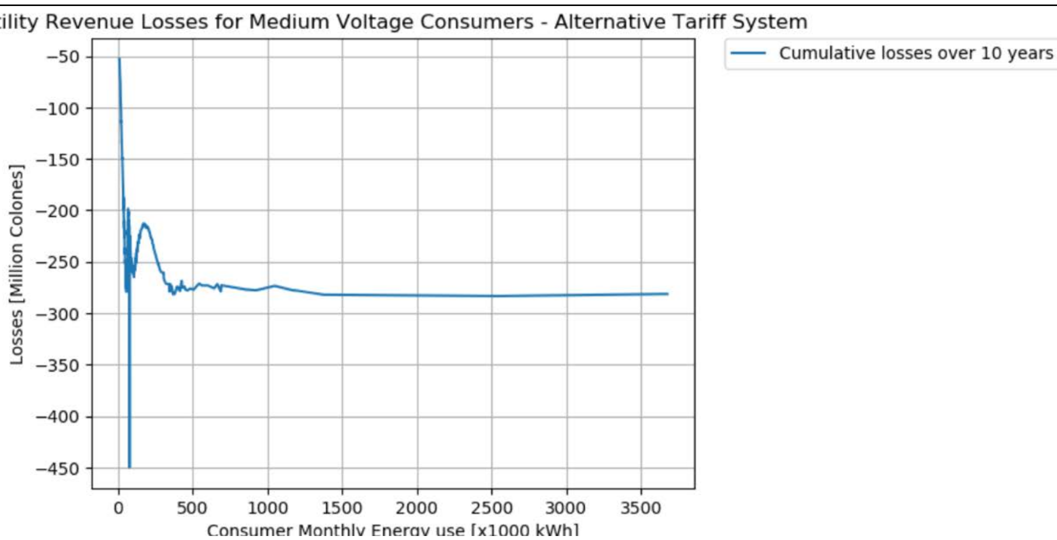
Current



CR 19,503 million

Total: CR 1,242,312 million

Neutral



CR 62,092 million

Total: CR 244,135 million

Source: Author's compilation.

10. Conclusions and Policy Recommendations

Under Costa Rican regulations, electricity generation is considered a public service and heavily regulated. Payments for electric power production depend on obtaining a concession from the

utilities commission and a contract with ICE. Private generation significantly increased under Law 7,200 during the Chinchilla Administration (2006-2010), and a large number of projects awarded at the time will come on line in the near future.

The framework of Law 7,200 was not meant to regulate, or limit, distributed generation, as this type of generation scheme didn't exist when the law came into force. Nevertheless, this created a regulatory problem when the Costa Rican government decided to make distributed generation a national priority and introduce net metering to promote it: under current regulations, consumers cannot sell electricity to the utility without meeting the conditions of Law 7,200, a practical impossibility for prosumers even if ICE were willing to issue new private generation contracts.

The solution to this dilemma was a resolution by the Procuraduría General de la República that created a fiction: when consumers generate more electricity than they consume, they are allowed to "deposit" the excess in the grid, and to "withdraw" it later. This mechanism was created under the belief that it would be neutral for the system.

Two limits were set regarding "deposits" and "withdrawals." For each individual circuit in the country, PV installed capacity can be no more than 15 percent of total circuit capacity. Furthermore, consumers can use up to 49 percent of their total energy generation without being considered providers of a public service. In practice, of course, consumers can generate a large percentage of their consumption, but they will receive a credit for electricity "deposited" in the grid only up to a point. Beyond that, there is are benefits for the consumer and the excess energy is injected into the grid for free.

With these provisions, including a creation volumetric charge linked to "withdrawals" to cover fixed costs, it was expected that distributed generation could grow without a negative impact on the net revenue of distribution utilities. However, the regulation did not consider distortions arising from the interaction of the regulatory framework with the current pricing scheme, nor did it account for the impact on the revenue of distribution utilities resulting from different prices charged by generators according to time of day.

The end result is that if all potential consumers installed PV systems up to the point at which they maximize 10-year net savings, net revenues would decrease significantly for distribution utilities. The goal of promoting distributed PV generation while ensuring the financial sustainability of the distribution utilities and, by implication, of the distribution infrastructure, is not achieved.

Our simulation exercises show, however, that under a pricing scheme that removes distortions in the current tariff scheme, the reduction of the utility's revenue is much smaller. Under neutral pricing, therefore, small upwards adjustments in demand charges would suffice to make the system financially sustainable.

In the long run, the optimal solution would be to dispense with the fiction of electricity "deposits" and "withdrawals" and to allow explicit sales and purchases of electricity with appropriate pricing mechanisms.

The transition to neutral pricing would, however, face considerable obstacles, as prices and bills for consumers that benefit from cross subsidies could increase significantly—a politically sensitive issue. A direct transfer to those consumers would solve the problem, without the distortions introduced by a tax-free, subsidized first consumption block, that benefits rich and poor consumers alike.

In conclusion, the fall in PV prices and a national policy to incentivize the adoption of distributed generation has created incentives for consumers to adopt this technology. However, older regulatory schemes have become a significant barrier to enable payments for excess generation from rooftop PV adopters and a significant financial risk for the publicly owned energy companies. The proposed pricing scheme reduces the negative impacts of large-scale adoption of PV in Costa Rica without requiring legal changes.

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