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Electricity planning under structural supply shortages: Coordinating public investment and household distributed energy resources

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Abstract : Electricity planning has increasingly accounted for distributed renewable energy resources (DREs) and active consumer participation. However, existing planning models generally assume that electricity supply is predominantly provided by generation assets under the control of the utility or system operator. This assumption breaks down in countries experiencing structural electricity shortages, where persistent supply deficits have prompted widespread private investment in diesel generators and rooftop photovoltaic (PV) systems outside the formal planning process. Electricity planning becomes a public-private coordination problem in which governments must jointly determine investments in centralized generation, DRE grid integration, and incentive mechanisms that shape household participation. This paper develops a planning framework for structurally shortage-prone electricity systems that jointly optimizes public investment in generation capacity, DRE grid integration, and feed-in tariff (FiT) design while explicitly accounting for endogenous household responses. We formulate the problem as a three-stage sequential game in which the government allocates investments and sets the FiT, households decide whether to participate, and the government subsequently determines electricity prices, feed-in volumes, and electricity supplied to consumers. The framework is empirically implemented through a case study of Lebanon. Results show that (i) under budget constraints, DRE grid integration is prioritized over additional centralized generation, (ii) appropriately designed FiTs induce substantial household participation, and (iii) DRE integration reduces annual electricity system costs by 8–37% and eliminates unserved demand under lower investment budgets than would otherwise be required.

Keywords: Electricity planning; electricity generation shortage; game theory; feed-in tariff; distributed renewable energy

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1 Introduction

Over the last five decades, electricity planning has evolved from a purely centralized paradigm toward one that increasingly accounts for market liberalization, distributed renewable energy resources (DREs), and active consumer participation (Pérez-Arriaga et al., 2017; Akcura and Mutambatsere, 2024). Traditional planning models focused on the least-cost expansion of centralized generation and network infrastructure to satisfy an exogenous electricity demand (Koltsaklis and Dagoumas, 2018; IRENA, 2018). More recent studies have extended these models by recognizing that DREs, particularly rooftop photovoltaic (PV) systems, influence electricity demand, investment requirements, and overall system costs (Burger et al., 2019).

Existing electricity planning models generally assume that the planner can reliably account for the available generation resources and that the bulk of electricity supply is provided through the interconnected power system. This assumption breaks down in systems with persistent shortages. In many developing countries, structural electricity supply shortages are the norm. For instance, Lebanon (Lawrie and Stubenberg, 2025), Iraq (Al-Wakeel, 2021), Nigeria (Obar et al., 2022), Yemen (Matallah et al., 2024), Afghanistan, Kenya, and several Sub-Saharan African countries (IEA et al., 2025) have experienced chronic electricity shortages and weak grid reliability. Public electric utilities in such countries do not possess enough generation capacity to meet the growing demand and face financial constraints preventing sufficient additional investments (Foster and Rana, 2020). When public supply persistently fails to satisfy demand, consumers increasingly make independent investment decisions that lie outside the formal planning process. Neighborhood diesel generators (DG) (Ahmad, 2020; Al-Wakeel, 2021; Lawrie and Stubenberg, 2025) and rooftop PV systems with batteries (Fheili and Nucho, 2024; Helou and Polese, 2024) are commonly adopted as electricity supply coping mechanisms under structural shortage (Olleik et al., 2026b). In an uncoordinated manner, the electricity system evolves into a hybrid public-private system where distributed private generation constitutes a sizable portion of the national capacity. Without appropriate incentives and network integration, much of the existing distributed capacity remains isolated from the public electricity system and cannot contribute efficiently to alleviating national shortages.

Governments in countries experiencing severe shortages face a choice in terms of electricity planning. On the one hand, they could focus on improving the central grid and increasing the centralized generation capacity despite their limited budgets. On the other, they could benefit from the large investments in distributed resources that consumers have already made and incorporate them in an efficient manner in the central grid. They could also encourage additional private investments that reduce the burden on public financing. This path, however, requires investments in network reinforcement and appropriate incentives. Accordingly, electricity planning transforms into a coordination problem between public and private investment aimed at improving electricity services under national budget constraints. This requires governments to jointly plan investments in centralized infrastructure and the integration of privately owned generation assets deployed outside the formal planning process.

Many countries with advanced electricity systems incentivized the installation of DRE technologies through different instruments including feed-in tariffs (FiTs), net metering, and renewable support schemes (Couture and Gagnon, 2010; IEA PVPS, 2024). These countries were mainly driven by decarbonization objectives. Under structural shortage, households have instead installed rooftop PV, often in off-grid configurations, out of necessity in response to unreliable national-grid supply (Merheb, 2024; Helou and Polese, 2024; Lawrie and Stubenberg, 2025). Accordingly, incentives for distributed generation in shortage-prone systems can pursue different objectives: making existing privately owned DREs available to reduce unmet demand (ESMAP, 2024) and mobilizing private capital (IEA, 2023; IFC, 2024) to reduce or defer utility-financed generation and network investments (Ahmad, 2020; ESMAP, 2024).

Yet, the success of any national electricity plan under structural shortage depends on the way the consumers respond to it. The heterogeneity caused by years of grid unreliability and the different backup options utilized shape the consumers' responses which in turn affect the conditions of the system that the electricity plan is designed to address. For example, government incentives for installing DRE resources affect the consumer adoption of such technologies (Jacksohn et al., 2019; Spiller et al., 2023). When additional DRE capacities are installed, additional investments in grid reinforcement are needed to accept the new electricity injections, which affects the overall system costs. This chain of reactions will then shape the cost-reflective electricity prices which will, in turn, affect the preferences of consumers for grid-based electricity, their backup options, or simply shortage. Hence, electricity planning under shortage requires a framework that jointly accounts for government-side decisions and proactive consumers' responses.

Existing studies have examined distributed resources within electricity planning and have separately analyzed incentive mechanisms for distributed generation. However, these two streams have evolved largely independently. Little attention has been paid to jointly determining centralized investment, network reinforcement, incentive design, and endogenous household responses in electricity systems operating under structural shortages.

Therefore, the purpose of this paper is to answer the following research question: How should governments design an electricity investment and distributed generation integration plan under structural electricity shortages while accounting for existing and potential consumer distributed resources? We particularly focus on consumer households as they possess the largest typical potential for distributed energy resources, especially solar PV (Khan et al., 2024; Lebanese MoEW and LCEC, 2025). The research question can be reformulated as two sub-questions:

1. How much of the constrained budget should the government allocate to investments in (i) generation capacity and (ii) DRE grid integration, including network reinforcement to accommodate household feed-in?
2. How should incentives be designed to induce efficient household participation? We particularly consider FiTs because they are better suited to the context of countries with less developed electricity systems (Elizondo Azuela and Barroso, 2012).

This paper provides three contributions:

- At the conceptual level, we formalize the electricity planning in shortage-prone systems as a joint public-private planning effort that cannot be done without incorporating the interactions between the market participants.
- At the methodological level, we formulate and solve a three-stage sequential game-theoretic model where the state acts first by allocating the investments in generation capacity and DRE grid integration in addition to setting the FiT. Households respond by participating or not participating in the FiT program, and the state subsequently determines the prevailing electricity price, the feed-in volumes and the electricity supplied to consumers.
- At the empirical level, we implement our modeling framework through a case study of Lebanon, a country where chronic public-supply shortage (World Bank, 2025), diesel-generator reliance (Ahmad, 2020; Lawrie and Stubenberg, 2025), and rapid rooftop PV adoption (Mitri and Hajj Chehadeh, 2025; Helou and Polese, 2024) make the problem empirically relevant.

The remainder of the paper proceeds as follows. Section 2 reviews the related literature on electricity planning with distributed generation and FiT design. Section 3 details the proposed game-theoretical model along with the solution approach. Section 4 introduces the Lebanese case study and the data used. Section 5 discusses the results and policy implications while Section 6 summarizes the main findings. Additional information is provided in five appendices. The data files, code, and complete result files are made available in a public GitHub repository.

2 Related works

Our work draws on, and contributes to, two strands of the literature: centralized electricity planning in the presence of distributed generation, and feed-in tariff design.

2.1 Centralized electricity planning accounting for distributed generation

Although DRE is increasingly included in centralized electricity planning, it is commonly represented through adjustments to load forecasts (Mims Frick et al., 2018), adoption forecasts (Willems et al., 2022), or predefined deployment scenarios (ESIG, 2024), rather than as an outcome of household responses to utility plans and policies. This approach may overlook decentralized responses to centralized planning decisions, even though PV adoption, self-consumption, and electricity feed-in alter the residual demand faced by the utility and may affect generation and network requirements (Burger et al., 2019).

A small body of literature captures decentralized responses through hierarchical models. Jin and Ryan (2014) use a tri-level formulation in which the transmission planner anticipates decentralized generation investment and subsequent market operation. Using Danish electricity-market data, Zugno et al. (2013) develop a bilevel model in which a retailer sets dynamic prices and consumers respond by adjusting their demand. Similarly, Erol and Başaran Filik (2022) formulate a single-leader, multiple-follower Stackelberg game in which prosumers adjust their consumption and energy-sharing decisions in response to prices set by a microgrid operator. In Chicago, Spiller et al. (2023) model household consumption and DRE investment responses under alternative residential tariff designs. Similarly, in Germany, Arnold et al. (2022) show that network tariffs influence residential PV investment under net purchasing. However, these studies capture decentralized responses to prices or preceding decisions without integrating them into centralized electricity planning under structural supply shortage.

In parallel, centralized planning has employed various incentives to promote DRE deployment and grid integration. FiTs provide an administratively set payment for electricity supplied to the grid and are widely used to support small renewable producers (Couture and Gagnon, 2010). Related feed-in compensation schemes include net metering and net billing, which set how electricity purchased from the grid and electricity supplied to the grid are valued (Benalcazar et al., 2024; Darghouth et al., 2011). Renewable-energy auctions competitively procure new capacity, mainly from utility-scale projects (Anatolitis et al., 2022; Matthäus, 2020). Virtual power plants (VPPs) aggregate and coordinate distributed generation, storage, and flexible demand so that these resources can jointly participate in energy and ancillary-service markets (Kaiss et al., 2025). Renewable portfolio standards (RPS), by contrast, require electricity suppliers to obtain a specified share of their electricity from renewable sources, often through renewable energy certificates (REC) or tradable green certificates (Zhang et al., 2018). These instruments differ in how they support renewable deployment, the actors they involve, and the institutional and market conditions they require.

These differences become particularly important in systems facing chronic electricity shortages and weak governing institutions. Auctions require credible procurement, competition, contract enforcement, and reliable payment arrangements (Anatolitis et al., 2022; Matthäus, 2020). VPPs depend on communication, monitoring, and control infrastructure (Kaiss et al., 2025), while RPS and certificate mechanisms require enforceable obligations and functioning certificate markets (Zhang et al., 2018). FiTs, by contrast, provide a direct administrative mechanism for compensating household electricity supplied to the grid and may be more suitable where institutional and market structures remain limited (Couture and Gagnon, 2010; Elizondo Azuela and Barroso, 2012). For this reason, FiT design is examined separately below.

2.2 Feed-in tariff design

FiTs are widely used to incentivize renewable investment and the efficient utilization of existing systems by compensating DRE owners for electricity fed into the grid (Couture and Gagnon, 2010; Yamamoto, 2012). In mature electricity systems, studies have mainly examined how FiT design affects renewable deployment, the profitability of PV investment, and power-sector decarbonization (Szendrei et al., 2025). Across six European countries, Campoccia et al. (2014) show that differences in tariff levels and implementation lead to substantially different profitability and investment incentives for PV producers. Comparing 27 EU countries, Alolo et al. (2020) find that the existence of a feed-in system does not necessarily increase renewable investment, as its effectiveness depends on contract design, technology, and market conditions. In Japan, Yamamoto (2012) uses a microeconomic model to compare FiTs, net metering, and net purchase and sale. Household response is represented through the price threshold for PV adoption and changes in electricity consumption, which subsequently affect social welfare and retail electricity prices. Later work examines how FiTs can be combined with capital subsidies to encourage residential PV adoption while limiting policy costs (Yamamoto, 2017).

In developing electricity markets, the literature places greater emphasis on financing and implementation conditions. In Kenya, FiTs generated investment interest but achieved limited project deployment, mainly because of implementation delays and insufficient technical expertise (Ndiritu and Engola, 2020). Evidence from six Southeast Asian economies shows that FiTs increased firm-level renewable investment, particularly in solar projects and among smaller and younger firms (Azhgaliyeva et al., 2024). In Tanzania, Moner-Girona et al. (2016) examine how FiTs can be adapted to existing and new remote mini-grids while accounting for local technical, economic, and institutional conditions. These studies show that FiTs can support renewable investment in developing markets, but their effectiveness depends strongly on the local context.

Only a few studies consider FiTs where unreliable electricity supply is itself a central concern. In Lebanon, Olleik et al. (2026a) account for uncertain grid-interconnection timing, electricity prices, and FiT levels when planning a hybrid renewable energy system. At the microgrid level, Bou Gebrael et al. (2026) develop a bilevel model in which a regulator sets electricity-price and FiT caps and show that these policies can increase household PV feed-in and household economic surplus under the market power of a diesel generator company. Yet, despite addressing FiTs under unreliable-grid conditions, these studies remain focused on decentralized community systems or local microgrids.

Table 1 summarizes the existing literature along several key dimensions, including shortage representation, the scope and main focus of the study, participant responses, the policy and pricing instruments considered, and the method adopted. Existing studies address these dimensions separately, but none combine national electricity investment and supply planning under unreliable grid conditions with FiT design that captures endogenous household responses within a single framework. Building on this literature, this paper proposes a national-level three-level framework in which the electric utility jointly determines generation investment, DRE grid-integration investment, existing generation operation, and the FiT, while household participation and feed-in decisions are determined through an equilibrium at the second level.

Table 1: Research position with respect to related work

Reference	Electricity shortage	Scope/Region	Main focus	Participant response	Policy and pricing instruments	Method
Azhgaliyeva et al. (2024)	No	Firms in Southeast Asia	Effect of FiTs on renewable investment	Firms adjust renewable investment	National FiT schemes	Firm-level empirical analysis
Alolo et al. (2020)	No	European renewable-energy markets	Effectiveness of feed-in systems	Investment response estimated empirically	FiTs and feed-in premiums	Panel-data empirical analysis
Arnold et al. (2022)	No	Household and distribution system	Network tariffs and PV investment	Households respond through PV investment	Network tariffs and net purchasing	Empirical and economic analysis
Bou Gebrael et al. (2026)	Yes	Local microgrid	Market power and distributed PV integration	Diesel generator company responds strategically	Electricity-price and FiT caps	Bilevel game-theoretic model
Campoccia et al. (2014)	No	National renewable-energy policy	PV profitability under support schemes	Investor response reflected through profitability	Country-specific FiTs	Comparative financial analysis
Erol and Başaran Filik (2022)	No	Community and microgrid	Energy-sharing pricing and scheduling	Prosumers respond strategically	Endogenous sharing price; no FiT	Stackelberg game
ESIG (2024)	No	National system planning	Generation and transmission expansion	DRE adoption follows scenarios	Exogenous tariff assumptions; no FiT	Capacity-expansion model
Jin and Ryan (2014)	No	National system and wholesale market	Transmission, generation, and market clearing	Generators make investment decisions	Endogenous wholesale prices; no FiT	Tri-level optimization
Moner-Girona et al. (2016)	No	Remote mini-grids	FiT adaptation for rural electrification	Investor response assessed through feasibility	Off-grid FiT	Integrated feasibility analysis
Ndiritu and Engola (2020)	No	National renewable-energy policy	FiT effectiveness and deployment barriers	Developer response assessed through outcomes	National FiT scheme	Policy and empirical analysis
Olleik et al. (2026a)	Yes	Community-level hybrid energy system	Planning under uncertain grid interconnection	Investment adapts to interconnection uncertainty	Grid price and FiT under uncertain interconnection	Deterministic and stochastic optimization
Spiller et al. (2023)	No	Household and distribution system	Tariff design and DRE adoption	Households choose DRE and electricity use	Residential tariff structures	DRE adoption model
Yamamoto (2012)	No	Household energy policy	PV compensation mechanisms	PV investment responds to compensation	FiT, net metering, and net purchase-sale	Economic and welfare analysis
Yamamoto (2017)	No	Household energy policy	FiTs and capital subsidies	PV investment responds to incentives	FiT and capital subsidy	Analytical economic model
Zhang et al. (2018)	No	National and regional power markets	Renewable deployment and policy costs	Producers respond through investment and generation	FiT, RPS, and REC trading	Power-market simulation
Zugno et al. (2013)	No	Retail electricity market	Retail pricing and demand response	Consumers adjust demand strategically	Endogenous retail price; no FiT	Bilevel leader–follower model
This paper	**Yes**	**National electricity-system planning**	**Utility investment and FiT design**	**Households choose participation and feed-in**	**FiT and endogenous electricity price**	**Three-level model with household equilibrium**

3 Methodology

We consider a public electric utility that is state-owned and whose mission is to provide electricity services on a non-profit basis. However, its generation capacity is insufficient to meet national electricity demand, resulting in persistent shortages. Consumers, particularly households, respond to these shortages by installing rooftop PV systems, connecting to neighborhood diesel generators, or tolerating part of their demand remaining unmet. The electric utility seeks to restore reliable electricity supply while breaking even to maintain its financial viability. Restoring the electricity sector, hence, requires the utility to expand public supply while accounting for the DRE developed by consumers outside the centralized system and for their responses to national electricity plan. In particular, consumer-owned PV can contribute to the recovery of public electricity supply when excess PV generation is made available to the system. The electric utility must thus coordinate investments in public generation and DRE grid integration with a FiT rate that encourages consumers to make this electricity available.

A national electricity plan designed for countries facing this context should account for the responses of consumers who already own PV systems or may decide to install them under the proposed plan.

We therefore formulate a game-theoretical model that captures the sequential and strategic interaction between the electric utility and households under generation shortage. Section 3.1 presents the model overview, Section 3.2 introduces the mathematical formulation, and Section 3.3 describes the solution approach.

3.1 Model overview

The proposed model examines how a public electric utility can restore electricity supply through generation and investment decisions while anticipating household responses to the FiT.

To translate this context into the model, we distinguish households according to the characteristics that can shape their decisions. Household responses depend mainly on whether they already own a PV system, whether they are connected to a DG, and whether they have sufficient rooftop space to install PV. Households connected to a DG use it to cover the demand not supplied by the electric utility, while households without a DG may tolerate part of their demand remaining unmet.

Based on these characteristics, households that already own PV systems or have sufficient rooftop space to install one are considered potential participants in the FiT program and are therefore represented as strategic players. The model considers four household categories:

$H1$: households that have PV systems and are not connected to a DG.

$H2$: households that have PV systems and are connected to a DG.

$H3$: households that do not have a PV system, are not connected to a DG, and have sufficient space to install PV.

$H4$: households that do not have a PV system, are connected to a DG, and have sufficient space to install PV. Households that do not own a PV system and cannot install one because of space limitations cannot participate in the FiT program and are therefore not strategic players in the model.

Figure 1 summarizes the status quo and the proposed model. Under the status quo, the limited electricity supplied by the electric utility is complemented by household PV self-consumption, neighborhood DG generation, or unmet demand. Under the proposed model, the electric utility can invest in new generation capacity, decide how much electricity to supply from its old generation capacity, invest in DRE grid integration, and introduce a FiT program for rooftop PV. Households that already own PV systems can make their excess generation available to the grid, while households without PV but with sufficient rooftop space can decide to install a system and participate in the program. The electricity fed into the grid is then used to reduce reliance on DG generation and lower electricity shortages.

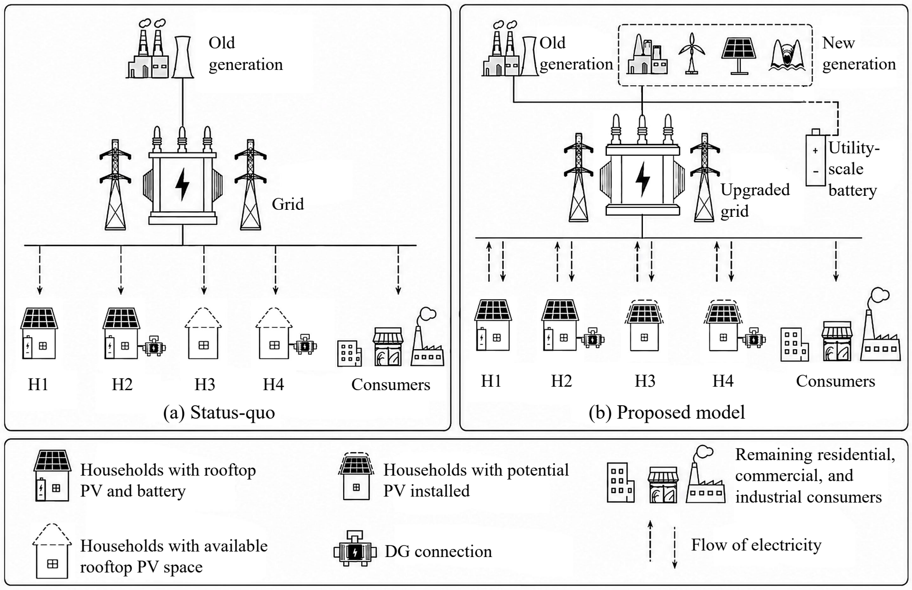


Figure 1: Model description

To represent this interaction, we formulate a three-stage sequential game in which the electric utility is the leader and the four household categories, $H1$–$H4$, are the followers, as shown in Figure 2.

In the first stage, the electric utility announces its decisions, namely, (i) the investment in new generation capacity, I_g, (ii) the investment in DRE grid integration, I_d, which includes the network reinforcement and storage support required to make fed-in electricity usable by the system, (iii) the feed-in tariff, FiT, and (iv) the yearly electricity supply from the old electric utility capacity, R_o. These decisions define the conditions to which the strategic household categories respond.

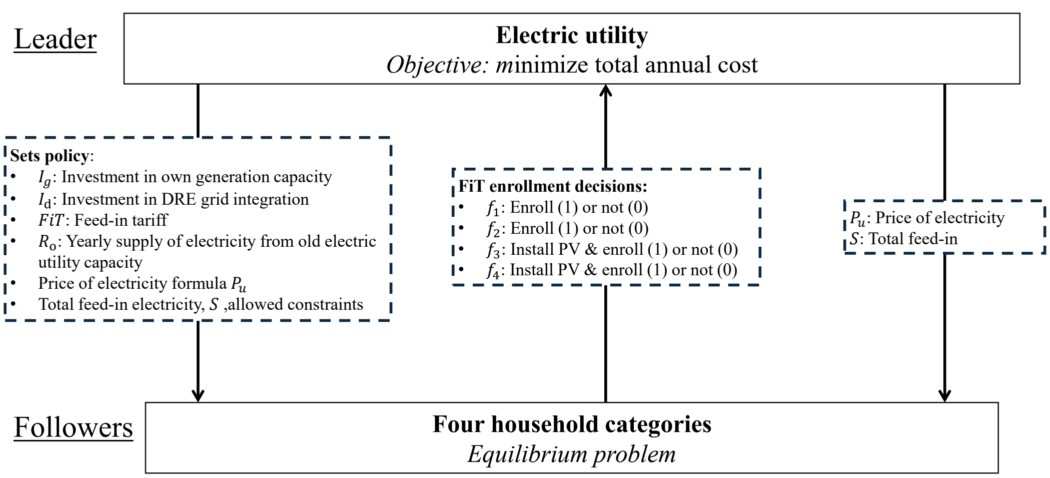


Figure 2: Information flow diagram

In the second stage, the four strategic household categories respond to the electric utility's decisions. Households in $H1$ and $H2$ decide either to enroll in the FiT program, ($f_i = 1$), or not, ($f_i = 0$). Households in $H3$ and $H4$ decide either to install a PV system and participate in the FiT program, ($f_i = 1$), or not to install PV, ($f_i = 0$). For any strategic household category, participation in the FiT program means that the household is willing to feed all excess PV electricity remaining after self-consumption into the grid. However, the actual amount fed into the grid depends on the electric utility's decisions and the system constraints. Any excess PV generation that cannot be integrated into the system is curtailed at the household level.

In the third stage, the outcomes of the game are determined through the state equations. These equations determine the total fed-in electricity and the electricity price that are consistent with the electric utility's decisions, the household participation decisions, and the system constraints.

3.2 Model

In this section, we introduce the model in two steps. First, we define the optimization problem of the electric utility in Section 3.2.1, and next the households' equilibrium problem in Section 3.2.2. The notation used throughout the paper, including the inputs, decision variables, and intermediate variables, is listed in Table 2.

Table 2: Notation

Symbol	Description	Unit
Input parameters		
μ_i	Yearly electricity demand of category i	kWh
μ_T	Total yearly electricity national demand	kWh
γ_u	Discount rate of electric utility	–
γ_i	Discount rate of category i	–
$\Psi_{pv,i}$	Annualized costs of PV system for category i	USD/year
ξ_o	Unit operational cost of the old electric utility power plants	USD/kWh
ξ_n	Unit operational cost of the new electric utility power plants	USD/kWh
ϕ_n	Average capacity factor of new electric utility power plants	–
κ_g	Capacity per USD of investment in new technology	kW/USD
ν	Lifetime of new electric power plants and grid extensions	Year
θ_i	Yearly potential PV electricity generated from category i	kWh
α_i	Share of PV electricity generated that is useful for category i	–
ζ_o	Yearly potential supply of electricity from old electric utility capacity	kWh
ρ_i	Value of lost load for category i	USD/kWh
ρ_u	Value of lost load for the electric utility	USD/kWh
π_{DG}	Price of DG electricity	USD/kWh
ω_i	PV system convenience factor of household i	USD/kWh
$\Gamma(\cdot)$	DRE grid integration capacity as a function of DRE grid integration investment	kWh/year
τ_u	Capital recovery factor for an interest rate γ_u and a life of ν years	–
Decision variables		
Electric utility		
I_g	Investments of the electric utility in expanding generation capacity	USD
I_d	Investments of electric utility in DRE grid integration	USD
FiT	Feed-in tariff	USD/kWh
R_o	Yearly supply of electricity from old electric utility capacity	kWh
Household categories		
f_i	Binary variable indicating if category i, $i \in \{1, \ldots, 4\}$, is enrolling in FiT policy	binary
Intermediate variables		
S	Total yearly fed-in electricity	kWh
SC	Total self-consumed PV generation	kWh
R_n	Yearly supply of electricity from new electric utility capacity	kWh
LL	Yearly lost load	kWh
P_u	Price of electricity sold by electric utility	USD/kWh

3.2.1 First-level

Let $\mathcal{S} = \{I_g,\ I_d,\ FiT,\ R_o\}$ denote the set of the electric utility's decision variables.

The objective function of the electric utility is to minimize its total annual cost. This cost includes the annualized investment cost in its own generation and DRE grid integration capacity, where τ_u represents the capital recovery factor for an interest rate γ_u and an equipment life of ν years. It also includes the running cost of the old generation capacity, given by the product of the yearly supply of electricity from old capacity, R_o, and its unit operational cost ξ_o, and the running cost of the new generation capacity, given by the product of the yearly supply from new capacity, R_n, and its unit operational cost ξ_n. In addition, the total cost accounts for the compensation paid for the feed-in from households, given by the product of the FiT and the total yearly feed-in electricity S. The electric utility is penalized for the lost load. This penalty is given by the product of the yearly lost load LL and the value of lost load for the electric utility ρ_u.

The electric utility objective is therefore given by

$$\begin{aligned}\min_{S} \quad U_u = \; & \underbrace{(I_g + I_d)\cdot\tau_u}_{\text{Annualized investment cost}} + \underbrace{\xi_o \cdot R_o}_{\text{Old generation running cost}} \\ & + \underbrace{\xi_n \cdot R_n}_{\text{New generation running cost}} + \underbrace{S \cdot FiT}_{\text{Feed-in compensation}} + \underbrace{LL \cdot \rho_u}_{\text{Lost-load penalty}} \end{aligned} \tag{1}$$

The electric utility's objective function is subject to the following constraints:

Old generation capacity constraint:

$$R_o \leq \zeta_o \tag{2}$$

The constraint in (2) limits the yearly electricity supplied from the old electric utility capacity, R_o, to the yearly potential supply available from the old power plants, ζ_o.

DRE grid integration constraint:

$$S \leq \Gamma(I_d) \tag{3}$$

The constraint in (3) limits the total fed-in electricity, S, according to the system's ability to integrate DRE, which depends on the investment needed to accommodate fed-in electricity, I_d. The function $\Gamma(I_d)$ denotes the DRE grid integration capacity. The formulation is kept general so that different relationships between investment and allowable feed-in can be adopted depending on the application. DRE grid integration investment can include both network upgrades required to accommodate fed-in electricity and storage support required to shift fed-in electricity to periods when it can be used to satisfy demand. One potential implementation of $\Gamma(\cdot)$ is provided in the case study.

Household excess-PV constraint:

$$S \leq \sum_{i=1}^{4} (1-\alpha_i)\cdot\theta_i\cdot f_i \tag{4}$$

The constraint in (4) limits total fed-in electricity to the excess PV generation available from the participating household categories. This corresponds to the part of their yearly potential PV generation that is not self-consumed. The parameter α_i represents the share of the yearly potential PV generation of category i that is used within the household, either through direct consumption or, when storage is available, after being stored for later use. Since periods of high PV generation do not always coincide with household consumption, part of the generated electricity remains in excess. The remaining share, $(1-\alpha_i)$, represents the excess PV generation available for feed-in and would otherwise be curtailed. The value of α_i is generally higher for households with battery storage, as part of the excess generation can be stored and used during later periods of demand (Wang et al., 2023).

Remaining demand constraint:

$$S \leq \mu_T - R_o - R_n - SC \tag{5}$$

The constraint in (5) ensures that total fed-in electricity does not exceed the remaining demand after self-consumed PV electricity, old generation, and new generation are accounted for.

The quantities used in the objective function and constraints are defined below.

New electric utility generation investment is assumed to follow a predetermined technology mix and represented by a single representative technology with given cost and technical characteristics. Accordingly, the yearly electricity supply from this new capacity, R_n, is given by

$$R_n = I_g \cdot \phi_n \cdot \kappa_g \cdot 8760 \tag{6}$$

where κ_g denotes the generation capacity installed per USD invested, ϕ_n is the average capacity factor of the representative generation mix, and 8760 is the number of hours in a year.

The total lost load, LL, is then defined as the part of total demand that is not covered by old and new electric utility generation capacity, self-consumed PV, and accepted total feed-in electricity:

$$LL = \mu_T - (R_o + R_n + S + SC) \tag{7}$$

It includes both the demand supplied through private DG generation and the demand that remains unmet.

The total self-consumed PV electricity, SC, is given by the useful share of the yearly potential PV generation of households $H1$, $\alpha_1\theta_1$, and $H2$, $\alpha_2\theta_2$, which already own PV systems, as well as that of households $H3$ and $H4$, given by $\alpha_3\theta_3 f_3$ and $\alpha_4\theta_4 f_4$, respectively, if they decide to participate in the FiT program and install PV systems. Accordingly, the self-consumed PV generation of $H3$ and $H4$ is multiplied by their corresponding participation decisions, f_3 and f_4:

$$SC = \alpha_1 \cdot \theta_1 + \alpha_2 \cdot \theta_2 + \alpha_3 \cdot \theta_3 \cdot f_3 + \alpha_4 \cdot \theta_4 \cdot f_4 \tag{8}$$

Finally, given that electricity is sold at cost, the electricity price, P_u, is defined as the ratio between the total annual electric utility cost and the total annual electricity sold by the electric utility (Equation 9). The total cost includes annualized investment in generation capacity and DRE grid integration capacity, $(I_g + I_d)\tau_u$, the running costs of old and new plants, $\xi_o R_o$ and $\xi_n R_n$, respectively, and the compensation paid for household feed-in, $S \cdot FiT$. The total electricity sold consists of the yearly supply from old and new generation capacity, R_o and R_n, respectively, and the fed-in electricity delivered back to households, S:

$$P_u = \frac{(I_g + I_d) \cdot \tau_u + \xi_o \cdot R_o + \xi_n \cdot R_n + S \cdot FiT}{R_o + R_n + S} \tag{9}$$

3.2.2 Second-level

The four strategic household categories, $H1$–$H4$, interact in the second stage. The household categories are distinguished by their economic characteristics, including their value of lost load, discount rate, and convenience associated with PV adoption. The relationships used to characterize each category are detailed in Appendix A. Each category i aims at minimizing its net annual electricity cost, given by the cost of purchasing electricity minus, when applicable, the revenues from feeding electricity into the grid.

To define the household equilibrium problem, two fairness variables are introduced: the share of the remaining electricity demand satisfied by the electric utility, α_u, and the share of each household category i in the total feed-in, $p_{i,S}$. These variables are used in the household objective functions. The electric utility is assumed to allocate its supplied electricity fairly across household categories, so that no category is given priority over another. Accordingly, α_u represents the common share of remaining demand supplied after self-consumption and is given by the ratio of total available electricity from old generation, new generation, and accepted feed-in to total remaining household demand, as shown in Equation 10:

$$\alpha_u = \frac{R_o + R_n + S}{\mu_T - SC} \tag{10}$$

Similarly, the fairness variable $p_{i,S}$ determines the share of total fed-in electricity allocated to each household category participating in the FiT program. Each participating category receives a share proportional to its own excess PV electricity relative to the total excess PV electricity available from all participating categories, as follows:

$$p_{i,S} = \begin{cases} 0, & \text{if } f_i = 0, \\ \dfrac{(1-\alpha_i)\cdot\theta_i\cdot f_i}{\sum_{j=1}^{4}(1-\alpha_j)\cdot\theta_j\cdot f_j}, & \text{if } f_i = 1, \end{cases} \qquad i = 1,\ldots,4. \tag{11}$$

Demand is treated as a parameter, while its level of satisfaction depends on the value of lost load. The household equilibrium problem is defined by the objective functions of the four strategic household categories, as presented below.

Household category 1 - $H1$ For a household in category $H1$, θ_1 denotes its yearly potential PV electricity generation. Only the share $\alpha_1\theta_1$ can be matched with household demand and self-consumed, while the remaining share cannot be consumed during PV generation hours or stored. If $H1$ enrolls in the FiT program ($f_1 = 1$), it makes up to $(1-\alpha_1)\theta_1$ available for feed-in. The actual amount fed into the grid depends on the electric utility's decisions and the participation decisions of the other household categories, as reflected by $p_{1,S}$.

The objective function of $H1$, therefore, consists of three components. First, $(\mu_1 - \alpha_1\theta_1)$ represents the household's remaining electricity demand after self-consumption of its useful PV generation. The share α_u determines the proportion of this remaining demand supplied by the electric utility. Hence, $\alpha_u(\mu_1 - \alpha_1\theta_1)$ is the electricity purchased from the utility at price P_u. Second, the remaining share, $(1-\alpha_u)(\mu_1-\alpha_1\theta_1)$, represents unmet demand and is valued at $H1$'s value of lost load, ρ_1. Third, when $H1$ participates in the FiT program, it earns revenue from its share of the total electricity accepted for feed-in at the FiT. The value of lost load represents the maximum amount a consumer is willing to pay to avoid an interruption in electricity supply (Crampes and Ambec, 2018; Schröder and Kuckshinrichs, 2015).

It is given by Equation 12:

$$\min_{f_1} \quad U_1 = \underbrace{\alpha_u\cdot(\mu_1-\alpha_1\cdot\theta_1)\cdot P_u}_{\text{Utility supplied electricity cost}} + \underbrace{(1-\alpha_u)\cdot(\mu_1-\alpha_1\cdot\theta_1)\cdot\rho_1}_{\text{Lost-load cost}} - \underbrace{p_{1,S}\cdot S\cdot FiT}_{\text{Feed-in revenue}} \tag{12}$$

Household category 2 - $H2$ Category $H2$ represents households with PV systems that are connected to DGs and do not tolerate electricity shortages.

DGs are widely used to compensate for limited utility supply, but at a significantly higher cost than electricity supplied by the electric utility (Ahmad, 2020). Accordingly, the electricity supplied by the electric utility is used first whenever it is available, while the DG is used only to cover any remaining unmet demand. In this sense, diesel generation acts as backup supply.

The objective function of $H2$ consists of three components: the cost of the part of the remaining demand satisfied by the electric utility at the price of electricity, P_u, the cost of any remaining demand not met through PV self-consumption or electric utility supply, which is covered by the DG to avoid shortages, at the DG electricity price π_{DG}, and the revenue from the electricity fed into the grid through $H2$'s share of the allowed total feed-in at the FiT, if $H2$ decides to participate in the FiT program. It is given by Equation 13:

$$\min_{f_2} \quad U_2 = \underbrace{\alpha_u \cdot (\mu_2 - \alpha_2 \cdot \theta_2) \cdot P_u}_{\text{Utility supplied electricity cost}} + \underbrace{(1-\alpha_u) \cdot (\mu_2 - \alpha_2 \cdot \theta_2) \cdot \pi_{DG}}_{\text{DG electricity cost}} - \underbrace{p_{2,S} \cdot S \cdot FiT}_{\text{Feed-in revenue}} \tag{13}$$

Household category 3 - $H3$ Category $H3$ represents households who do not have any PV system and are not connected to DGs, and can therefore tolerate electricity shortages.

The objective function of $H3$ consists of four components: the cost of the portion of its remaining demand, after PV self-consumption if it decides to install PV and participate in the FiT program, that is supplied by the electric utility at the electricity price P_u, the monetary loss associated with any unmet demand, valued at $H3$'s value of lost load, ρ_3, the annualized PV system cost, $\Psi_{pv,3}$, incurred if $H3$ installs PV and participates, and the revenue earned from $H3$'s share of the total electricity accepted for feed-in at the FiT, if $H3$ participates. It is given by Equation 14:

$$\min_{f_3} \quad U_3 = \underbrace{\alpha_u \cdot (\mu_3 - \alpha_3 \cdot \theta_3 \cdot f_3) \cdot P_u}_{\text{Utility supplied electricity cost}} + \underbrace{(1-\alpha_u) \cdot (\mu_3 - \alpha_3 \cdot \theta_3 \cdot f_3) \cdot \rho_3}_{\text{Lost-load cost}} + \underbrace{\Psi_{pv,3} \cdot f_3}_{\text{Annualized PV system cost}} - \underbrace{p_{3,S} \cdot S \cdot FiT}_{\text{Feed-in revenue}} \tag{14}$$

Household category 4 - $H4$ Category $H4$ represents households who do not have any PV systems and are connected to DGs and therefore do not tolerate electricity shortages.

The objective function of $H4$ consists of four components: the cost of the portion of its remaining demand, after PV self-consumption if it decides to install PV and participate in the FiT program, that is supplied by the electric utility at the electricity price P_u, the cost of any remaining demand that must be covered by the DG to avoid shortages, at the DG electricity price π_{DG}, the annualized PV system cost, $\Psi_{pv,4}$, incurred if $H4$ installs PV and participates; and the revenue earned from $H4$'s share of the total electricity accepted for feed-in at the FiT rate, if $H4$ participates. It is given by Equation 15:

$$\min_{f_4} \quad U_4 = \underbrace{\alpha_u \cdot (\mu_4 - \alpha_4 \cdot \theta_4 \cdot f_4) \cdot P_u}_{\text{Utility supplied electricity cost}} + \underbrace{(1-\alpha_u) \cdot (\mu_4 - \alpha_4 \cdot \theta_4 \cdot f_4) \cdot \pi_{DG}}_{\text{DG electricity cost}} + \underbrace{\Psi_{pv,4} \cdot f_4}_{\text{Annualized PV system cost}} - \underbrace{p_{4,S} \cdot S \cdot FiT}_{\text{Feed-in revenue}} \tag{15}$$

We note that the objective functions of H1–H4 depend on one another's decisions through S, P_u, $p_{i,S}$, and α_u. Therefore, determining the optimal decisions requires identifying the Nash equilibrium among the four household categories.

3.3 Solution approach

The method starts with input computation and parameter initialization, then loops over all candidate first-level plans, evaluates the corresponding household responses, and finally retains the plan that minimizes the electric utility's worst-case cost.

The proposed model gives rise to a constrained optimization problem in which several state variables depend on the second-level household strategies. The second level itself is a Nash equilibrium problem with binary household decisions f_i. In addition, both the electric utility's objective function and the household objective functions are non-linear, particularly through their dependence on fed-in electricity and the electricity price P_u. This structure makes a direct analytical solution difficult.

Figure 3 presents the solution approach adopted at a high level through four main blocks. The explanation of each block is provided below.

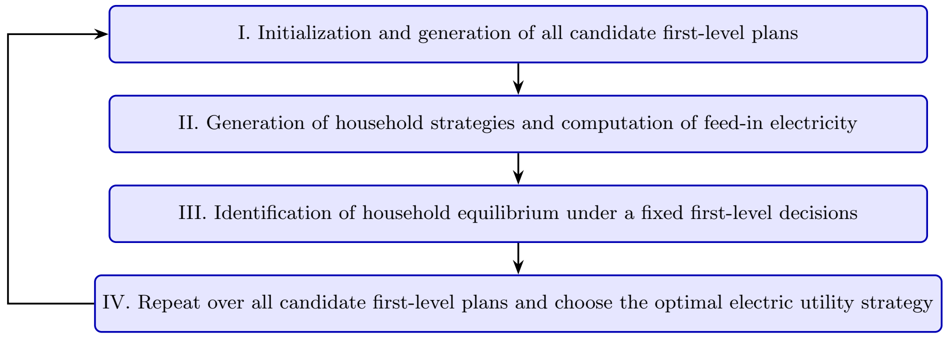


Figure 3: High-level structure of the solution approach

1. **Block I: Initialization and generation of first-level plans**
   All exogenous inputs and case-study parameters are initialized using the data described in Section 4. The feasible ranges and step sizes of the electric utility's first-level decision variables (I_g, I_d, FiT, R_o) are then defined. These ranges reflect the technical, political, and budgetary limits of the case study, and determine the grid of feasible first-level decisions combinations to be evaluated.
2. **Block II: Generation of household strategies and computation of feed-in electricity**
   For each candidate feasible first-level plan, the candidate household strategies are generated. As established in Proposition 1 below, $H1$ and $H2$ decisions are fixed at

   $$f_1 = 1, \qquad f_2 = 1.$$

   Hence, only the four possible combinations of $(f_3, f_4) \in \{0,1\}^2$ are enumerated.

   Proposition 1 (Dominant FiT participation of $H1$ and $H2$)**.** For any fixed first-stage electric utility decisions (I_g, I_d, FiT, R_o) and any fixed strategies of the other household categories, participation in the FiT program is a dominant strategy for the PV-owning household categories $H1$ and $H2$. In particular,

   $$f_1^\star = 1, \qquad f_2^\star = 1.$$

   The proof is provided in Appendix B.

   For each candidate solution $(I_g, I_d, FiT, R_o, f_1, \ldots, f_4)$, the intermediate quantities are then computed using the model equations. These include the yearly supply from new generation, R_n (Equation 6), the total PV self-consumption, SC (Equation 8), and the three limits on total feed-in S arising from grid capacity, household excess PV, and remaining demand (Equations 3, 4, and 5).

   To determine the maximum feasible feed-in electricity, let S_{grid}, S_h, and S_{need} denote, respectively, the maximum feed-in allowed by the network, the total excess PV from participating households, and the remaining demand after self-consumption, old capacity, and new capacity. The maximum feasible feed-in is calculated as

   $$S_{\max} = \min\{S_{grid}, S_h, S_{need}\}.$$

   The actual level of feed-in is then determined according to the following proposition.

   Proposition 2 (Optimal feed-in decision)**.** For fixed first- and second-level decisions $(I_g,\ I_d,\ FiT,\ R_o,\ f_i\ \ \forall i \in \{1,2,3,4\})$, the electric utility's total cost is linear in the feed-in variable S. In particular,

   $$U_u(S) = S \cdot (FiT - \rho_u) + C,$$

   where C groups all fixed terms that do not depend on S.

The optimal feed-in decision is therefore given by

$$S^* = \begin{cases} S_{\max}, & \text{if } FiT < \rho_u, \\ 0, & \text{if } FiT \geq \rho_u, \end{cases}$$

where ρ_u is the electric utility's value of lost load.

The proof is provided in Appendix C.

3. **Block III: Identification of household equilibrium under a fixed first-level decisions**

   Once the feed-in outcome is determined, the remaining state variables are computed. These include total lost load, LL, from the balance equation (Equation 7), the share of remaining demand satisfied by the electric utility, α_u (Equation 10), the feed-in shares $p_{i,S}$ across household categories (Equation 11), and the electricity price P_u (Equation 9).

   Using these quantities, the objective functions of the four household categories are evaluated according to Equations 12–15. Then, to identify the household equilibrium, the objective functions of $H3$ and $H4$ are compared, for each feasible candidate strategy solution, with those obtained under unilateral deviations in their own decisions. A candidate solution is retained as a second-level Nash equilibrium if neither $H3$ nor $H4$ can improve its objective functions by deviating alone.

   Since the household functions are formulated here as net costs, the Nash equilibrium condition is interpreted in a minimization sense. Accordingly, a household has no incentive to deviate if no unilateral deviation can reduce its cost.

   For a given first-level sets of decisions (I_g, I_d, FiT, R_o), one or several household equilibria may exist. If multiple equilibria arise, the equilibrium that yields the highest total cost for the electric utility is retained, reflecting a conservative worst-case view of household reactions. The corresponding worst-case cost is obtained from the electric utility objective function in Equation 1.

4. **Block IV: Choosing the optimal electric utility strategy**

   The procedure is repeated for all candidate first-level plans. The final solution is the combination $(I_g^*, I_d^*, FiT^*, R_o^*)$ that yields the lowest worst-case total cost for the electric utility.

The detailed implementation of the algorithm is presented in Appendix D. The steps are grouped according to the same four numbered blocks used in Figure 3.

4 Case study

We apply our model described in Section 3.2 to Lebanon's electricity sector. Lebanon is a clear example of the broader dilemma studied in this paper. The country has experienced a prolonged electricity crisis, with electricity supplied by the state-owned utility, Electricité du Liban (EDL), available for only a few hours per day (World Bank, 2025). As a result, households rely heavily on DG and PV self-generation to cover, at least partially, the remaining demand (Madelain, 2023; Ahmad, 2020).

This electricity shortage reflects the inability of EDL to meet national demand using the existing conventional generation. The existing public power plants are inefficient and costly to operate, which makes recovery difficult under limited public budgets (Olleik et al., 2025). At the same time, many households rely on private diesel generators to compensate for EDL outages, while rooftop PV adoption increased rapidly following the electricity crisis. A recent national assessment estimates that cumulative installed PV capacity reached approximately 1,254 MWp by 2023 (Mitri and Hajj Chehadeh, 2025). This expansion has largely been driven by the need for energy security under persistent shortages, rather than by a coordinated national planning strategy (Lebanese MoEW and LCEC, 2025).

Despite this rapid growth, the integration of household-level PV into the broader electricity system remains limited. Most systems operate mainly behind the meter for self-consumption, while the absence of a stable framework for grid access and compensation limits the value of exporting excess production (Ahmad, 2020). In response, Lebanon ratified the Decentralized Renewable Energy Law No. 318 in December 2023, which formalizes decentralized renewable energy and includes grid-connected options that rely on a FiT mechanism (LCEC, 2023). Still, key implementation details related to FiT pricing and grid integration remain practical challenges, especially under weak institutional capacity and continuing shortage (Madelain, 2023; Foster and Rana, 2020).

The household side is represented through the four categories defined in Section 3.1. Households $H1$ and $H2$ already own PV systems and are represented with behind-the-meter batteries, consistent with the household survey dataset reported by Dbouk et al. (2025). Households $H3$ and $H4$ do not own PV systems but have sufficient rooftop space to install them and may participate in the FiT program. They are modeled without household-level battery storage, so that their excess PV generation can be made available through the feed-in mechanism. The specifications of the four household categories, expressed per representative household in each category, are shown in Table 3.

Table 3: Specifications of the household categories in Lebanon case study

Category	Monthly demand[a] (kWh/mo)	Weight[b,*]	PV capacity[c] (kW)	Battery capacity[c] (kWh)	α_i[d]	Value of lost load[e] (\$/kWh)	γ_i[e]	ω_i[e] (\$/kWh)
$H1$	528	10.0%	3.0	4.8	0.7	0.30	0.05	0.00
$H2$	704	20.0%	4.0	9.6	0.7	1.00	0.05	0.00
$H3$	100	18.3%	1.0[**]	0.0	0.5	0.20	0.08	0.00
$H4$	528	24.4%	3.0[**]	0.0	0.5	0.41	0.05	0.24

[*] The remaining household weight, equal to 27.3%, is assigned to households without sufficient rooftop space to install PV.
[**] Potential PV capacity if enrolled in the FiT program.
[a] PV systems are properly sized relative to household demand (Renewable Energy Agency Puducherry, 2025).
[b] The household-category weights are derived from national estimates of poverty, PV ownership, and DG reliance reported by World Bank (2024), Arab Barometer (2024), and UNHCR et al. (2019). The shares of households unable to install PV are estimated from the household survey reported by Dbouk et al. (2025).
[c] Existing PV capacities and behind-the-meter battery capacities for $H1$ and $H2$, as well as the potential PV capacities for $H3$ and $H4$, are adapted from the household survey dataset reported by Dbouk et al. (2025).
[d] The useful PV shares are differentiated according to battery availability, based on the residential self-consumption evidence reported by Murano et al. (2025) and the battery specifications reported by Lazard (2025).
[e] The values of lost load, household discount rates, γ_i, and convenience parameters, ω_i, are determined using the relationships defined in Appendix A.

To reduce shortage and make household feed-in useful at the system level, the utility can operate the existing public generation capacity, invest in new centralized generation, and reinforce the network while setting the FiT. New utility generation is modeled through a representative generation mix taken from the Ministry's planned generation expansion mix (Ministry of Energy and Water, 2019). The representative generation mix specifications are shown in Table 4.

For the grid side, the relationship between the investment needed to accommodate fed-in electricity, I_d, and allowable fed-in electricity, S, is written as a linear function (Gupta et al., 2021). This is consistent with the planning-level representation adopted in this work. Accordingly, the DRE grid integration capacity function is specified as

$$\Gamma(I_d) = \beta_d \cdot I_d + \upsilon_{net}, \tag{16}$$

where β_d measures the additional annual feed-in capacity enabled per USD invested in DRE grid integration, including both network upgrades required to accommodate household feed-in and storage support required to shift fed-in electricity to periods when it can be used to satisfy demand if needed. The symbol υ_{net} represents the initial grid feed-in capacity without additional investment.

The model is implemented in Python and solved using the solution approach described in Section 3.3, based on a grid search over the first-level decision variables within the predefined bounds detailed in Appendix E. The input data, their sources, and the scripts used to generate the results are available in the project's GitHub repository[1]. The computations were performed on a computer equipped with a 13th-generation Intel Core i7-1355U processor with 10 cores, 12 logical processors, and 39.6 GB of usable RAM. On this configuration, the unconstrained case evaluated 367,455 grid points and required approximately 46 minutes to solve.

Table 4: Representative generation mix specifications

Technology	Share[a]	Unit CAPEX[b] ($/kW)	Fixed unit OPEX[b] ($/kW/year)	Variable OPEX[b] ($/kWh)	Heat rate[b] (BTU/kWh)	Fuel cost[c] ($/MMBTU)	Life[b] (year)	Capacity factor[d]
OCGT	0.319	812.5	15.0	0.00460	8900	17.1255	20	0.93
CCGT	0.487	1600.0	16.5	0.00385	6525	17.1255	20	0.93
PV	0.085	975.0	21.8	0.00000	0	0	20	0.22
Wind	0.110	1300.0	44.5	0.00000	0	0	20	0.14

Notes: CAPEX = capital expenditure; OPEX = operating expenditure.
[a] Technology shares are taken from the generation expansion plan reported in Ministry of Energy and Water (2019).
[b] Unit capital costs, fixed and variable non-fuel operating costs, technology lifetimes, and heat-rate values for OCGT and CCGT are reported by Olleik et al. (2025) for OCGT, CCGT, and wind, and by Hatton et al. (2024) for solar PV.
[c] The natural-gas fuel cost is based on the natural-gas benchmark reported by CME Group (2026).
[d] The capacity factors for wind and solar PV are derived from renewable-resource profiles reported by Renewables.ninja (2024).

5 Results

The results are presented in three parts. Section 5.1 examines the optimal electricity plan under different planning constraints. It starts with the unconstrained case, which identifies the optimal plan when the electric utility can undertake the required investments, and then considers two additional constraints that may affect this plan in practice: (i) limiting the electric utility's total investment budget and (ii) requiring old generation to operate before new generation. Section 5.2 examines the economic value of integrating household DREs into the main grid through FiT incentives. Section 5.3 examines the sensitivity of the optimal plan to the share of fed-in electricity requiring storage under alternative investment budgets.

5.1 Planning under different investment constraints

This section examines the optimal utility plan and the resulting household responses under different planning constraints.

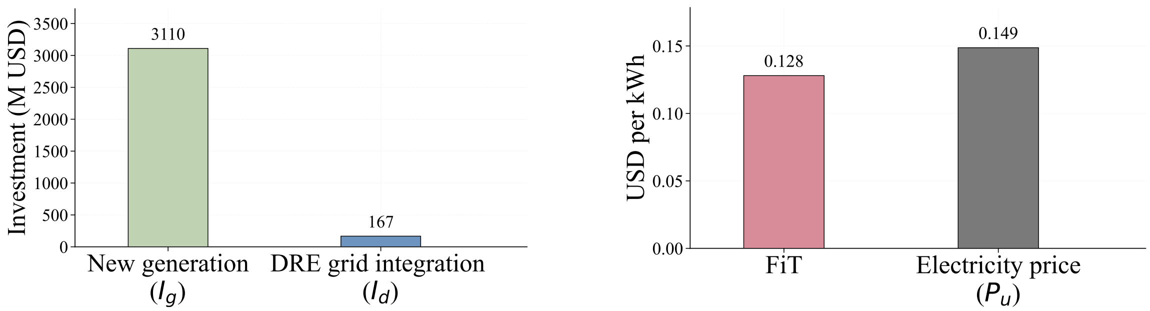
5.1.1 Unconstrained case

In this case, the assumption is that the electric utility has, or can secure, sufficient financial resources to undertake both new generation investment and DRE grid integration investment. It therefore serves as a benchmark for the constrained planning cases.

Figure 4 presents the optimal electric utility decisions. Figure 4a shows investments of 3,110 million USD in new generation and 167 million USD in DRE grid integration, while Figure 4b shows an optimal FiT of 0.128 USD/kWh and an electricity price of 0.149 USD/kWh. The FiT remains below the electricity price, while the combined investment and pricing decisions expand utility generation and create the conditions for household DRE integration.

Given these utility decisions, Figure 5 presents the resulting household equilibrium. All four household categories participate in the FiT program and 100% of the excess PV available after self-consumption is fed into the grid by each household category.

[1] https://github.com/molleik/Elec_Policy_DRE



(a) Electric utility investment decisions **(b) Feed-in tariff and electricity price**

Figure 4: Unconstrained case electric utility decisions and resulting electricity price

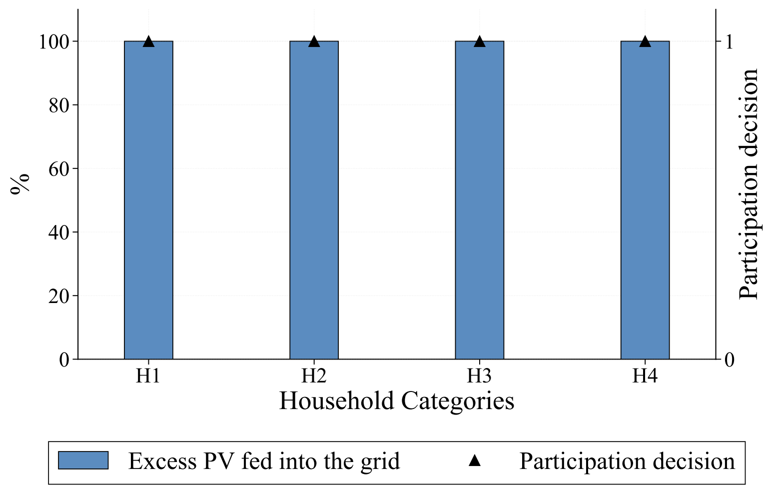


Figure 5: Unconstrained case household participation decisions and share of excess PV fed into the grid by household category

Combining the utility decisions with the household equilibrium, Figure 6 shows that 72% of the total demand is supplied by new utility generation, 17% is covered through household PV self-consumption, and the remaining 11% is supplied through household electricity fed into the grid. Total demand is therefore fully satisfied without old utility power plants and private diesel generation. Household PV contributes to the system in two ways: Self-consumption reduces the electricity that must be supplied directly by the utility, while electricity fed into the grid provides an additional source for meeting the remaining demand.

5.1.2 Financial and political constrained cases

The unconstrained planning outcome described above may change when the electric utility operates under constraints that are typical of shortage-prone electricity systems. In particular, the results are examined under two conditions: (i) limited financial capability for the initial investment required for generation expansion and DRE grid integration, and (ii) mandatory use of old generation before new generation. The first condition reflects the difficulty faced by financially constrained utilities in securing the capital needed to implement the optimal plan and therefore requires the utility to adjust its decisions to the available investment budget. The second reflects situations in which existing thermal plants continue to operate for operational, political, or institutional reasons, even when their use does not correspond to the least-cost supply mix.

When the available budget is tight, the electric utility prioritizes DRE grid integration (Figure 7). As soon as enough investments in DRE grid integration are made so that all household categories

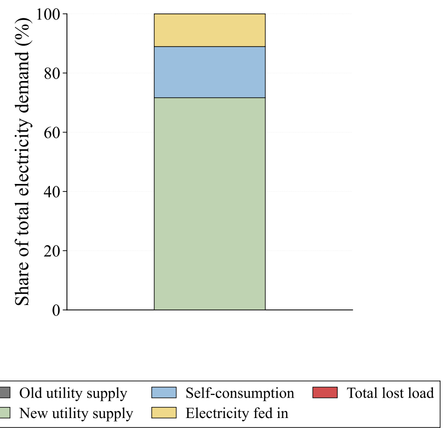


Figure 6: Unconstrained case electricity supply mix as a share of total demand

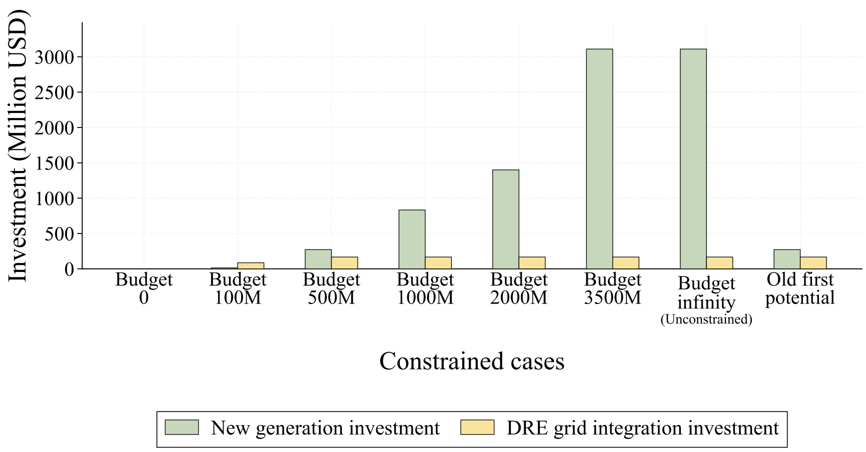


Figure 7: Optimal electric utility investment decisions under financial and political constraints

participate, additional investments are directed towards new generation capacity. At 3,500 million USD, the investment constraint is no longer binding and the unconstrained outcome is reproduced. In the old-generation-first case, the investment pattern is similar to the 500 million USD case, DRE grid-integration investment remains at the needed level, while new generation investment is lower because old utility capacity supplies part of the remaining demand.

Focusing on the utility cost structure, Figure 8 shows that when the investment budget is at or below 100 million USD, the electricity system is naturally dominated by the old generation capacity and the running costs of the existing plants cover the bulk of the annual expenditures. A share of 15% of the total demand remains unserved. With higher budgets, unserved demand is eliminated and DRE grid integration investments are prioritized entailing FiT payments for participating households. At a budget of 3,500 million USD, enough new capacity is built to phase out the old power plants.

Figure 9 compares the optimal FiT and the resulting electricity price. The FiT increases with the available budget. The electricity price is highest under the tightest budgets because supply remains dominated by costly old generation. It generally decreases as investment increases and reaches its lowest level at 3,500 million USD, where the least-cost supply mix is achieved. In the old-generation-first case, the electricity price remains higher because part of demand continues to be supplied by old utility generation, which is more expensive than the least-cost mix.

In terms of household participation, categories $H1$ and $H2$ participate even when the FiT is zero and the system cannot accept all their excess PV (Figure 10). Because these households already own

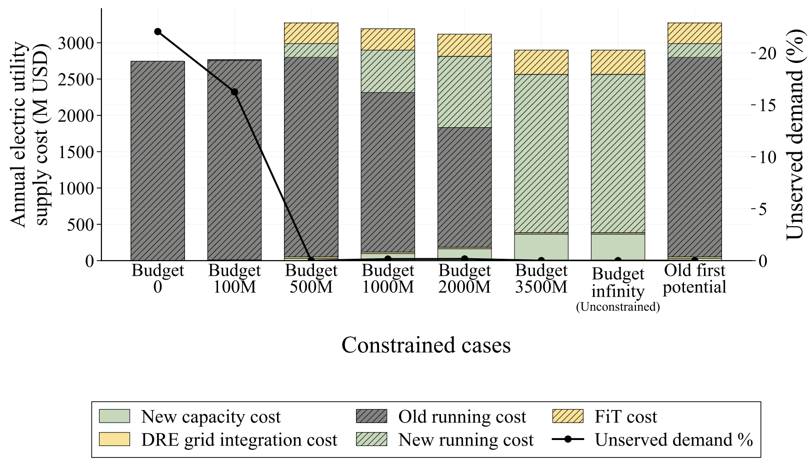


Figure 8: Annual electric utility supply cost and unserved demand under financial and political constraints

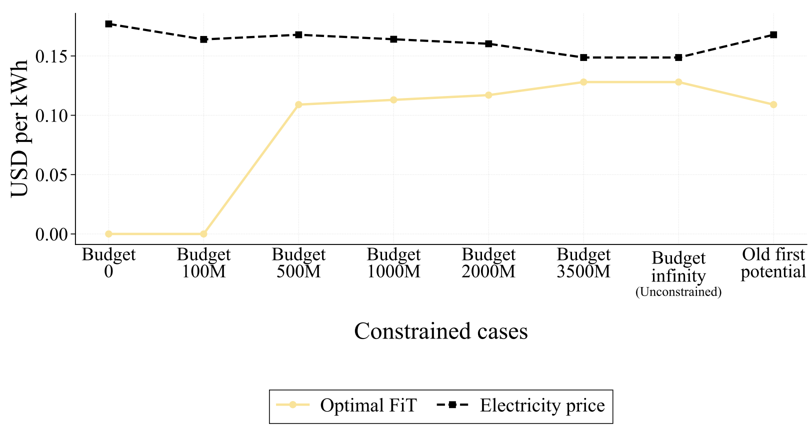


Figure 9: Optimal FiT and electricity price under financial and political constraints

PV systems, participation does not require an additional investment and allows part of the electricity that would otherwise be curtailed to be used by the system which ends up reducing the electricity price. Category $H3$ also invests in PV and participates under tight budgets even without feed-in compensation. PV self-consumption reduces the electricity it must purchase from the utility, while its feed-in contributes to lowering the electricity price. Since $H3$ is particularly sensitive to the electricity price, these combined benefits make PV investment and participation worthwhile. Category $H4$, in contrast, participates only from the 500 million USD budget level onward, when the FiT is high enough and DRE grid-integration investment is sufficient to accept all of its excess PV. Since $H4$ must invest in PV, already has access to DG supply, and faces the additional convenience barrier included in the model, participation becomes economically attractive only when its excess generation is fully utilized and adequately compensated.

Building on the previous results, Figure 11 shows the evolution of the supply mix under different constrained scenarios. Investment budgets of 500 million USD are needed to eliminate shortage. Prioritizing DRE grid integration investments maximizes and flattens the contribution of households to the energy mix in both self-consumption and feed-in for budgets exceeding 167 million USD. If enough investment budget is available, the old power plants are eliminated from the system and considerable new generation capacity is built.

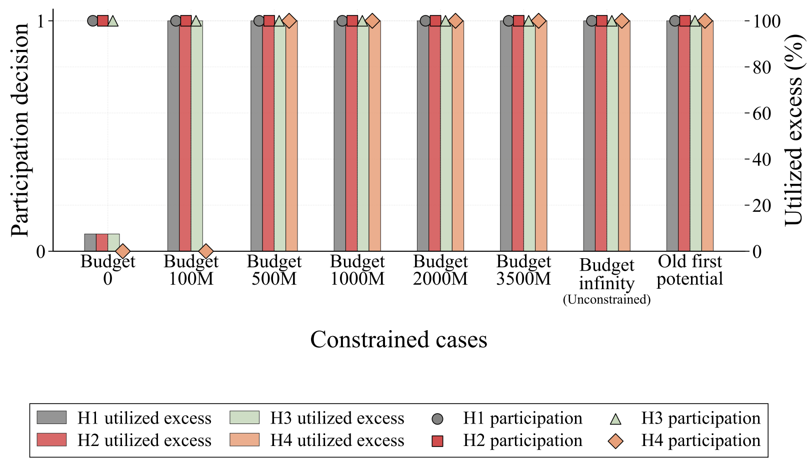


Figure 10: Household participation and utilized excess PV under financial and political constraints

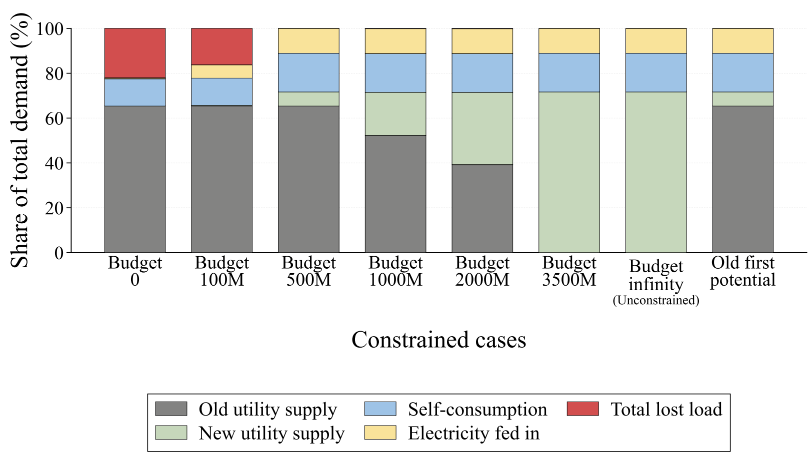


Figure 11: Electricity supply mix under financial and political constraints

5.2 Economic value of integrating DREs into the grid

To assess the economic value of integrating household DREs into the grid, we compare the outcomes without and with DRE grid integration under investment budgets of 100, 500, and 1,000 million USD, as well as under an unconstrained budget. In the case without DRE grid integration, households can still self-consume part of their PV generation, but excess PV electricity is not bought by the electric utility and cannot be used as a system-level supply source.

Under the 100 million USD budget, DRE integration increases household self-consumption as more households install PV and allows part of the excess PV generation to be fed into the grid, reducing unserved demand without eliminating it completely (Figure 12). At the 500 million USD budget, the effect becomes more significant. Without DRE grid integration, part of the demand remains unserved, whereas allowing household feed-in eliminates unserved demand. At the 1,000 million USD budget, DRE grid integration reduces reliance on old utility generation. Under the unconstrained budget, demand is fully satisfied in both cases. However, without DRE grid integration, the system relies mainly on new utility generation, while integrating household DREs allows household self-consumption and fed-in electricity to replace part of this centralized generation.

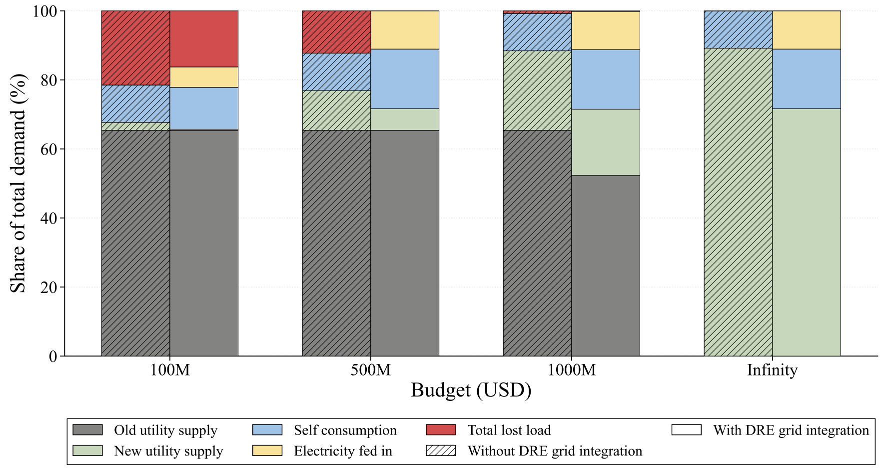


Figure 12: Electricity supply mix without and with DRE grid integration through FiT incentives under different investment budgets

These findings are further reflected in Figure 13, which compares the total annual electric utility cost, including the economic cost of unserved demand. Integrating DREs into the grid through FiT incentives decreases this cost by 14%, 37%, 13%, and 8% under the 100, 500, and 1,000 million USD budgets and the unconstrained budget, respectively. The largest reduction occurs at the 500 million USD budget because DRE grid integration eliminates the unserved demand that remains when household feed-in is not allowed.

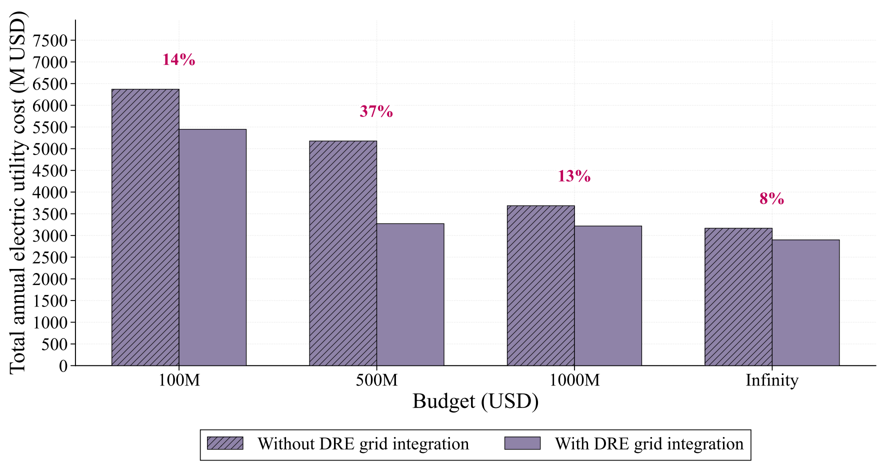


Figure 13: Total annual electric utility cost with and without DRE grid integration through FiT incentives under different investment budgets

Figure 14 shows that the electricity price also decreases when DREs are integrated into the grid through FiT incentives under all investment budgets. At the lowest budget, the electricity price decreases from 0.177 to 0.164 USD/kWh, while under the unconstrained budget it decreases from 0.151 to 0.149 USD/kWh. The reduction becomes smaller under the unconstrained budget because the utility already has sufficient financial resources to meet demand through new generation without old generation and household feed-in.

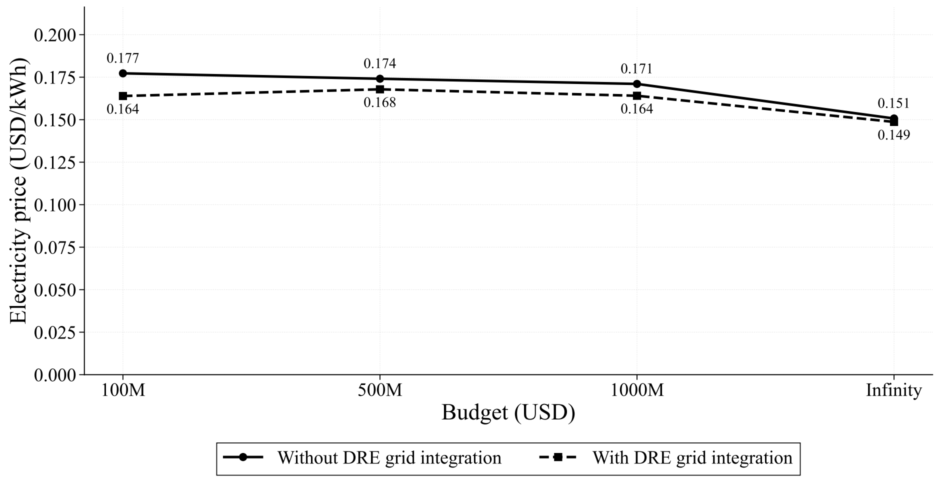


Figure 14: Electricity price with and without DRE grid integration through FiT incentives under different investment budgets

5.3 Sensitivity analysis of the share of fed-in electricity requiring storage

This section assesses the robustness of the optimal investment plan to changes in the share of fed-in electricity requiring storage under alternative investment budgets.

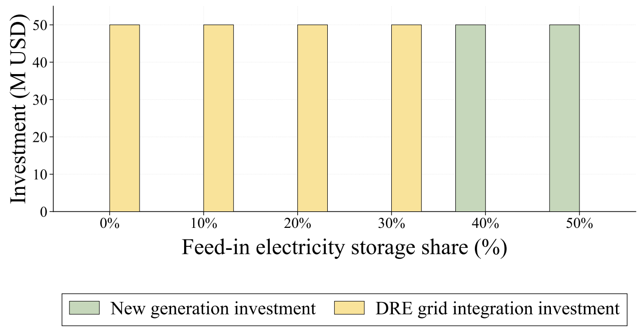
Across the previous results, the storage share is set to 0%. Since households are the only source of electricity fed into the grid and the system faces persistent shortage across all sectors, accepted feed-in is assumed to be used directly to meet residual demand. However, part of this electricity may not coincide with demand and may require storage before it can be used. The analysis therefore considers storage shares ranging from 0% to 50% under investment budgets of 50 and 500 million USD and an unconstrained budget.

Figure 15 compares new generation and DRE grid integration investment as the storage share increases. DRE grid integration investment includes the network reinforcement and storage support requirement.

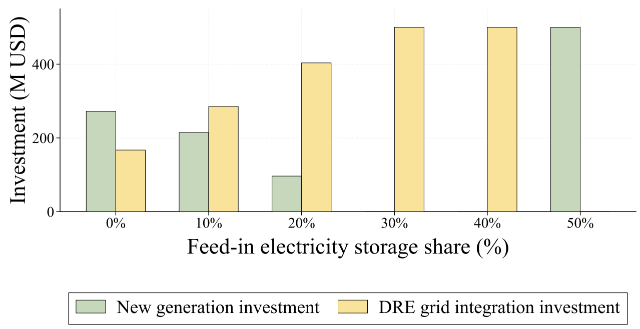
Under the 50 million USD budget, shown in Figure 15a, the utility allocates the available budget to DRE grid integration for storage shares up to 30%. At higher shares, the required battery capacity makes integration more costly, and the utility shifts toward new generation investment.

Under the 500 million USD budget, shown in Figure 15b, the utility initially invests in both new generation and DRE grid integration. As the storage share remains below 50%, DRE grid-integration investment rises while new generation investment declines reflecting the continued prioritization of grid integration investments. At 50%, integration becomes too costly, and the utility instead allocates the full budget to new generation.

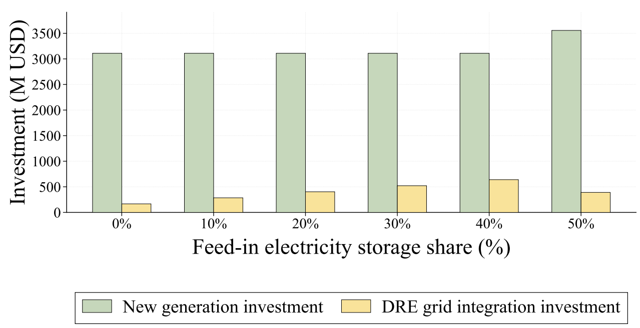
Under the unconstrained budget, shown in Figure 15c, the utility can invest in both options. From 0% to 40%, higher storage requirements increase DRE grid-integration investment, while new generation investment remains stable to meet the remaining demand. At 50%, the utility increases new generation investment to achieve a more cost-effective supply mix, while maintaining a lower level of DRE grid-integration investment to retain part of the benefits of households participation.



(a) Budget = \$50M



(b) Budget = \$500M



(c) Budget = \$ ∞

Figure 15: Optimal electric utility investment decisions under different feed-in storage requirements and investment budgets

6 Conclusion

Structural electricity shortages fundamentally change the nature of electricity planning. As households increasingly invest in distributed generation outside the formal planning process, governments must jointly determine investments in centralized infrastructure, distributed renewable energy resource (DRE) grid integration, and incentive mechanisms under constrained public budgets. Electricity planning therefore becomes a public-private coordination problem rather than a purely centralized investment exercise.

To address this challenge, this paper develops a planning framework that jointly optimizes investments in generation capacity, DRE grid integration, and feed-in tariff (FiT) design while explicitly accounting for endogenous household responses. The problem is formulated as a three-stage sequential game between the government and heterogeneous households and is demonstrated through the Lebanese electricity sector, where chronic electricity shortages, widespread diesel-generator reliance, and rapid rooftop PV adoption make these interactions particularly relevant.

The analysis shows that explicitly accounting for privately owned DREs leads to different planning decisions than conventional centralized planning. Under constrained public investment budgets, the preferred strategy prioritizes DRE grid integration before expanding centralized generation capacity, allowing existing household-owned PV resources to contribute to system supply. Once the optimal level of DRE grid integration is achieved, additional public investment is directed toward centralized generation to eliminate the remaining supply shortage. The analysis further shows that FiTs, together with sufficient grid-integration investment, encourage participation across all capable household categories, increase PV self-consumption, and mobilize privately owned generation to support the public electricity system. Comparing planning scenarios with and without DRE grid integration demonstrates that household feed-in reduces electricity-system costs across all investment budgets while lowering the public investment required to eliminate unserved demand. These planning insights remain robust when part of the household feed-in requires storage before being utilized.

Overall, the analysis indicates that privately owned distributed resources become an integral component of electricity planning once they represent a significant share of electricity supply. Rather than relying exclusively on additional centralized generation, governments can leverage existing and future private investment to improve electricity-system performance while reducing the burden on scarce public financial resources.

The proposed framework remains subject to two main limitations. First, from an electricity-system representation perspective, the model is formulated on an annual basis to capture long-term investment and participation decisions while maintaining computational tractability. Consequently, the model abstracts from short-term operational dynamics, including hourly renewable generation variability, battery dispatch, and network constraints. Second, from an institutional representation perspective, the strategic interaction is limited to the government and aggregate household categories. Future research can address these limitations by considering more detailed representations of electricity-system operation and by expanding the institutional representation to include private diesel-generator providers, commercial prosumers and independent investors as strategic decision makers.

7 Declaration of generative AI and AI-assisted technologies in the manuscript preparation process

During the preparation of this work, the authors used ChatGPT by OpenAI to improve the readability of the manuscript, assist in debugging the Python scripts, and generate the visual icons used in Figure 1. After using this tool, the authors reviewed and edited all outputs as needed and take full responsibility for the content of the published article.

A Household characterization

The household categories differ in their access to PV and DG generation, their electricity demand, their ability to tolerate shortages, and their willingness to invest in alternative electricity sources. These characteristics are reflected in the determination of each category's value of lost load.

Households in $H1$ are not connected to DG either because they prefer to avoid reliance on expensive and polluting diesel power or because they are located in areas where DG networks are not well established (Human Rights Watch, 2023; Olleik et al., 2026b). They self-consume their PV electricity and rely on the electric utility to cover their remaining demand in order to avoid shortages.

The value of lost load for $H1$, ρ_1, is assumed to be higher than the levelized cost of their PV system and the unit operational cost of the old electric utility power plants, but lower than the DG price. The relations in Equations 17, 18, and 19 are used to determine ρ_1 within this range:

$$\rho_1 \geq LCOE_{PV+Bat,1} \tag{17}$$

$$\rho_1 \geq \xi_o \tag{18}$$

$$\rho_1 \leq \pi_{DG} \tag{19}$$

$H2$ represents households that currently have installed PV systems, including PV panels and battery storage, and are connected to a DG. These households have the financial capability to invest in both PV and DG, ensuring a continuous power supply (Olleik et al., 2026b). They self-consume as much PV generation as possible, then use the electric utility to satisfy their remaining demand, and finally rely on DG for any residual unmet demand.

The value of lost load for $H2$, ρ_2, is assumed to be higher than the levelized cost of their PV system, the DG price, and the unit operational cost of the old electric utility power plants. The relations in Equations 20, 21, and 22 are used to determine ρ_2 within this range:

$$\rho_2 \geq LCOE_{PV+Bat,2} \tag{20}$$

$$\rho_2 \geq \pi_{DG} \tag{21}$$

$$\rho_2 \geq \xi_o \tag{22}$$

Households in $H3$ are typically among the poorest in society, with limited financial capacity to invest in alternative energy sources (Dagher et al., 2023). As a result, they rely solely on the electric utility, which makes them the most vulnerable to power shortages (Human Rights Watch, 2023). The value of lost load for $H3$, ρ_3, is assumed to be lower than the levelized cost of a PV system and the DG price, but higher than the running cost of the old electric utility power plants. The relations in Equations 23, 24, and 25 are used to determine ρ_3 within this range:

$$\rho_3 \leq LCOE_{PV+Bat,3} \tag{23}$$

$$\rho_3 \leq \pi_{DG} \tag{24}$$

$$\rho_3 \geq \xi_o \tag{25}$$

Category $H4$ represents households that have not installed any PV systems but are connected to a DG. These households generally have the financial capability and the necessary space to install PV systems. However, they are not willing to deal with the hassle associated with owning and operating a full PV system, including PV panels and batteries, such as installation, maintenance, and the management of three different sources of energy (Sandin Lompar and Neij, 2025; Mutumbi et al., 2026). Instead, they choose to rely on the electric utility when it is available and on diesel generators when it is not (Olleik et al., 2026b). A monetary convenience factor, ω_4, is added to the levelized cost of the PV system to reflect their hesitation and the practical difficulties they associate with switching to solar energy, since non-financial "hassle" barriers are known to discourage households from adopting renewable technologies even when they are economically attractive (Meles et al., 2022). This factor is therefore incorporated into the annualized PV system cost for category $H4$, $\Psi_{pv,4}$. These households prefer to use all electricity supplied by the electric utility to meet their demand and then rely on the relatively more expensive DG. The value of lost load for $H4$, ρ_4, is assumed to be related to the different cost levels as follows:

$$\rho_4 \leq LCOE_{PV+Bat,4} + \omega_4 \tag{26}$$

$$\rho_4 \geq \pi_{DG} \tag{27}$$

$$\rho_4 \geq \xi_o \tag{28}$$

All the relations presented above are used for parameter determination and are not imposed as constraints in the model.

B Proof of proposition 1

A strategy $a_i^\star \in \mathcal{A}_i$ is a *dominant strategy* for player i if, for any alternative strategy $a_i \in \mathcal{A}_i$ with $a_i \neq a_i^\star$,

$$u_i(a_i^\star, a_{-i}) \leq u_i(a_i, a_{-i}), \qquad \forall\, a_{-i} \in \mathcal{A}_{-i},$$

where

$$\mathcal{A}_{-i} = \prod_{j \neq i} \mathcal{A}_j$$

(Parilina et al., 2022). This definition is stated in a minimization sense, as applicable to the household objective functions in the equilibrium problem. In the proposed model, dominance for $H1$ and $H2$ is established by comparing the household objective function under $f_i = 1$ and $f_i = 0$, for an arbitrary strategy solution of the other household categories f_{-i}, with $i \in \{1, 2\}$. Consider a given electric utility first-level set of decisions, (I_g, I_d, FiT, R_o), and an arbitrary fixed candidate solution for the strategies of the other household categories of f_{-i}. Let U_i^0 denote the objective function of household category i when $f_i = 0$, and let U_i^1 denote the objective function when $f_i = 1$, for $i \in \{1, 2\}$. Then,

$$U_i^0 = \alpha_u^0 \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot P_u^0 - p_{i,S}^0 \cdot S^0 \cdot FiT + (1 - \alpha_u^0) \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot \varphi_i,$$

and

$$U_i^1 = \alpha_u^1 \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot P_u^1 - p_{i,S}^1 \cdot S^1 \cdot FiT + (1 - \alpha_u^1) \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot \varphi_i,$$

where

$$\varphi_i = \begin{cases} \rho_1, & \text{if } i = 1, \\ \pi_{DG}, & \text{if } i = 2 \end{cases}$$

In addition, given a fixed first-level electric utility decision (I_g, I_d, FiT, R_o) and a fixed candidate solution for the strategies of the other household categories, f_{-i}, the decision of household category $i \in \{1, 2\}$ affects the following quantities.

First, the share of household category i from the total feed-in satisfies

$$p_{i,S}^0 = 0,$$

and

$$p_{i,S}^1 = \frac{(1 - \alpha_i) \cdot \theta_i}{\sum_{j=1}^{4} (1 - \alpha_j) \cdot \theta_j \cdot f_j}$$

Second, the share of the remaining electricity demand satisfied by the electric utility is given by

$$\alpha_u^0 = \frac{R_o + R_n + S^0}{\mu_T - SC},$$

and

$$\alpha_u^1 = \frac{R_o + R_n + S^1}{\mu_T - SC}$$

Third, the electricity price is given by

$$P_u^0 = \frac{R_o \cdot \xi_o + R_n \cdot \xi_n + S^0 \cdot FiT + (I_g + I_d) \cdot \tau_u}{R_o + R_n + S^0},$$

and

$$P_u^1 = \frac{R_o \cdot \xi_o + R_n \cdot \xi_n + S^1 \cdot FiT + (I_g + I_d) \cdot \tau_u}{R_o + R_n + S^1}$$

Next, by Proposition 2, and for a fixed first-level decision and fixed f_{-i}, the implemented feed-in levels S^0 and S^1 are determined as follows.

If $FiT \geq \rho_u$, then

$$S^0 = 0, \qquad S^1 = 0.$$

Hence, the implemented feed-in does not change when f_i switches from 0 to 1.

If $FiT < \rho_u$, then

$$S^0 = \min\left\{S_{grid},\, S_h^0,\, S_{need}\right\},$$

where

$$S_{grid} = \Gamma(I_d),$$

$$S_{need} = \mu_T - (R_o + R_n + SC),$$

and

$$S_h^0 = \sum_{j \neq i} (1 - \alpha_j) \cdot \theta_j \cdot f_j.$$

where $j \in \{1, 2, 3, 4\}$ and $j \neq i$.

Similarly,

$$S^1 = \min\left\{S_{grid},\, S_h^1,\, S_{need}\right\},$$

where

$$S_h^1 = (1 - \alpha_i) \cdot \theta_i + \sum_{j \neq i} (1 - \alpha_j) \cdot \theta_j \cdot f_j.$$

where $j \in \{1, 2, 3, 4\}$ and $j \neq i$.

Since S_{grid} and S_{need} depend only on the fixed first-level decision and the fixed decisions of the other household categories, they do not change with f_i. The only term affected by the switch from $f_i = 0$ to $f_i = 1$ is the household feed-in upper bound, and clearly

$$S_h^1 \geq S_h^0.$$

Therefore, two main cases arise.

Case 1: $FiT \geq \rho_u$ By Proposition 2,

$$S^1 = S^0 = 0.$$

Hence, the implemented feed-in does not change when household category i switches from $f_i = 0$ to $f_i = 1$. It follows immediately that

$$\alpha_u^1 = \alpha_u^0, \qquad P_u^1 = P_u^0,$$

and since

$$p_{i,S}^0 = 0 \quad \text{and} \quad S^1 = S^0 = 0,$$

the FiT revenue term is also zero in both cases. Therefore,

$$U_i^1 = U_i^0.$$

Case 2: $FiT < \rho_u$ In this case, by Proposition 2,

$$S^0 = \min\{S_{grid}, S_h^0, S_{need}\}, \qquad S^1 = \min\{S_{grid}, S_h^1, S_{need}\}$$

We distinguish two subcases:

Subcase 2.1: $S_h^0 \geq S_{need}$ *or* $S_h^0 \geq S_{grid}$

If

$$S_h^0 \geq S_{need} \quad \text{or} \quad S_h^0 \geq S_{grid},$$

then the household-excess bound is not binding when $f_i = 0$. Since

$$S_h^1 \geq S_h^0$$

it follows that the household-excess bound is also not binding when $f_i = 1$. Therefore, in both cases the implemented feed-in is determined by the same binding term among S_{need} and S_{grid}, so that

$$S^1 = S^0.$$

Since S does not change, the other quantities that depend on it also do not change. In particular,

$$\alpha_u^1 = \alpha_u^0, \qquad P_u^1 = P_u^0$$

Also,

$$p_{i,S}^1 > p_{i,S}^0 = 0$$

Hence,

$$U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT \leq 0$$

Therefore,

$$U_i^1 \leq U_i^0.$$

Subcase 2.2: $S_h^0 < S_{need}$ *and* $S_h^0 < S_{grid}$.

In this case, the household-excess bound is binding when $f_i = 0$, and therefore

$$S^0 = S_h^0$$

Two situations may then arise depending on the value of S_h^1.

If

$$S_h^1 \geq S_{need} \quad \text{or} \quad S_h^1 \geq S_{grid},$$

then the household-excess bound is no longer binding when $f_i = 1$, and

$$S^1 = \min\{S_{need}, S_{grid}\}$$

Since

$$S_h^0 < S_{need} \quad \text{and} \quad S_h^0 < S_{grid},$$

it follows that

$$S^1 > S^0$$

If instead

$$S_h^1 < S_{need} \quad \text{and} \quad S_h^1 < S_{grid},$$

then the household-excess bound remains binding when $f_i = 1$, and

$$S^1 = S_h^1$$

Since

$$S_h^1 \geq S_h^0,$$

we obtain

$$S^1 \geq S^0$$

Thus, in all situations covered by this subcase,

$$S^1 \geq S^0.$$

Therefore, to establish dominance in this subcase, the objective function difference between $f_i = 1$ and $f_i = 0$ can be written as

$$\begin{aligned} U_i^1 - U_i^0 =& \alpha_u^1 \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot P_u^1 - p_{i,S}^1 \cdot S^1 \cdot FiT + (1 - \alpha_u^1) \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot \varphi_i \\ & - \alpha_u^0 \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot P_u^0 + p_{i,S}^0 \cdot S^0 \cdot FiT - (1 - \alpha_u^0) \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot \varphi_i \end{aligned}$$

Since

$$p_{i,S}^0 = 0,$$

this becomes

$$\begin{aligned} U_i^1 - U_i^0 =& \alpha_u^1 \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot P_u^1 - p_{i,S}^1 \cdot S^1 \cdot FiT + (1 - \alpha_u^1) \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot \varphi_i \\ & - \alpha_u^0 \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot P_u^0 - (1 - \alpha_u^0) \cdot (\mu_i - \alpha_i \cdot \theta_i) \cdot \varphi_i \end{aligned}$$

Factoring out the common term $(\mu_i - \alpha_i \cdot \theta_i)$ gives

$$U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT + (\mu_i - \alpha_i \cdot \theta_i) \cdot \left[\alpha_u^1 \cdot P_u^1 + (1 - \alpha_u^1) \cdot \varphi_i - \alpha_u^0 \cdot P_u^0 - (1 - \alpha_u^0) \cdot \varphi_i\right]$$

Rearranging the terms inside the bracket yields

$$U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT + (\mu_i - \alpha_i \cdot \theta_i) \cdot \left[\alpha_u^1 \cdot P_u^1 - \alpha_u^0 \cdot P_u^0 - (\alpha_u^1 - \alpha_u^0) \cdot \varphi_i\right]$$

Now substituting

$$\alpha_u^0 = \frac{R_o + R_n + S^0}{\mu_T - SC}, \qquad \alpha_u^1 = \frac{R_o + R_n + S^1}{\mu_T - SC},$$

we get

$$U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT + \frac{\mu_i - \alpha_i \cdot \theta_i}{\mu_T - SC} \cdot \left[(R_o + R_n + S^1) \cdot P_u^1 - (R_o + R_n + S^0) \cdot P_u^0 - (S^1 - S^0) \cdot \varphi_i\right]$$

Replacing P_u^1 and P_u^0 by their expressions gives

$$\begin{aligned} U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT + \frac{\mu_i - \alpha_i \cdot \theta_i}{\mu_T - SC} \Bigg[& \big(R_o \cdot \xi_o + R_n \cdot \xi_n + S^1 \cdot FiT + (I_g + I_d) \cdot \tau_u\big) \\ & - \big(R_o \cdot \xi_o + R_n \cdot \xi_n + S^0 \cdot FiT + (I_g + I_d) \cdot \tau_u\big) - (S^1 - S^0) \cdot \varphi_i \Bigg] \end{aligned}$$

Cancelling the common terms $R_o\xi_o$, $R_n\xi_n$, and $(I_g + I_d)\tau_u$ yields

$$U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT + \frac{\mu_i - \alpha_i \cdot \theta_i}{\mu_T - SC} \left[S^1 \cdot FiT - S^0 \cdot FiT - (S^1 - S^0) \cdot \varphi_i\right]$$

Factoring out $(S^1 - S^0)$ gives

$$U_i^1 - U_i^0 = -p_{i,S}^1 \cdot S^1 \cdot FiT + \frac{\mu_i - \alpha_i \cdot \theta_i}{\mu_T - SC}(S^1 - S^0) \cdot (FiT - \varphi_i)$$

Since

$$-p_{i,S}^1 \cdot S^1 \cdot FiT \leq 0, \qquad S^1 - S^0 \geq 0, \qquad FiT - \varphi_i \leq 0,$$

it follows that

$$U_i^1 - U_i^0 \leq 0,$$

and therefore

$$U_i^1 \leq U_i^0.$$

Hence, choosing $f_i = 1$ dominates choosing $f_i = 0$ in this subcase.

Combining all cases, we obtain that, for any fixed first-level electric utility decision (I_g, I_d, FiT, R_o) and any fixed candidate solution for the strategies of the other household categories, f_{-i}, choosing $f_i = 1$ yields a net cost at least as low as choosing $f_i = 0$, for $i \in \{1, 2\}$. Therefore, participation in the FiT program is a dominant strategy for household categories $H1$ and $H2$.

C Proof of proposition 2

Starting from the electric utility's objective function,

$$U_u = (I_g + I_d) \cdot \tau_u + R_o \cdot \xi_o + R_n \cdot \xi_n + S \cdot FiT + LL \cdot \rho_u,$$

and substituting the expression for the lost load,

$$LL = \mu_T - (R_o + R_n + S + SC),$$

we obtain

$$U_u = (I_g + I_d) \cdot \tau_u + R_o \cdot \xi_o + R_n \cdot \xi_n + S \cdot FiT + \big(\mu_T - R_o - R_n - S - SC\big) \cdot \rho_u$$

Rearranging the terms gives

$$U_u = (I_g + I_d) \cdot \tau_u + R_o \cdot (\xi_o - \rho_u) + R_n \cdot (\xi_n - \rho_u) + S \cdot (FiT - \rho_u) + (\mu_T - SC) \cdot \rho_u$$

For the purpose of this proposition, consider the set of first- and second-level decisions

$$\mathcal{S}' = \{I_g,\ I_d,\ FiT,\ R_o,\ \ f_i\ \forall i \in \{1,2,3,4\}\}$$

and treat $\mathcal{S}'$ as fixed. Then R_n and SC are also fixed through Equations 6 and 8, and the only remaining decision of the electric utility is the total feed-in electricity S, which is limited by three technological bounds:

1. **Grid limit.** The network can accommodate at most:

$$S_{grid} = \Gamma(I_d)$$

2. **Household generation limit.** Only the non-self-consumed portion of PV generation may be fed into the grid:

$$S_h = \sum_i (1 - \alpha_i)\,\theta_i\,f_i$$

3. **Remaining demand limit.** Feed-in cannot exceed the remaining demand after self-consumption, old capacity, and new capacity are accounted for:

$$S_{need} = \mu_T - (R_o + R_n + SC)$$

Therefore, the feasible region for S is

$$0 \le S \le S_{\max}, \qquad S_{\max} = \min\{S_{grid},\ S_h,\ S_{need}\}$$

For fixed $\mathcal{S}'$, the utility's objective can be written as

$$U_u(S) = S \cdot (FiT - \rho_u) + C,$$

where C groups all terms that do not depend on S. The derivative of U_u with respect to S is

$$\frac{\partial U_u}{\partial S} = FiT - \rho_u$$

Case 1: $FiT < \rho_u$ In this case, $\frac{\partial U_u}{\partial S} < 0$, so $U_u(S)$ is strictly decreasing in S over the feasible interval. Increasing S reduces the utility's total cost, and the minimum is therefore reached at the upper bound:

$$S^* = S_{\max}$$

Case 2: $FiT \geq \rho_u$ Here, $\frac{\partial U_u}{\partial S} \geq 0$, so $U_u(S)$ is non-decreasing in S. Any positive feed-in would increase or leave unchanged the total cost. The minimum is therefore reached at the lower bound:

$$S^* = 0$$

Combining both cases yields the optimal feed-in rule:

$$S^* = \begin{cases} S_{\max}, & \text{if } FiT < \rho_u, \\ 0, & \text{if } FiT \geq \rho_u \end{cases}$$

This completes the proof of Proposition 2.

D Detailed solution algorithm

Figure 16 presents the detailed implementation of the solution algorithm. The steps are grouped according to the same four numbered blocks used in Figure 3.

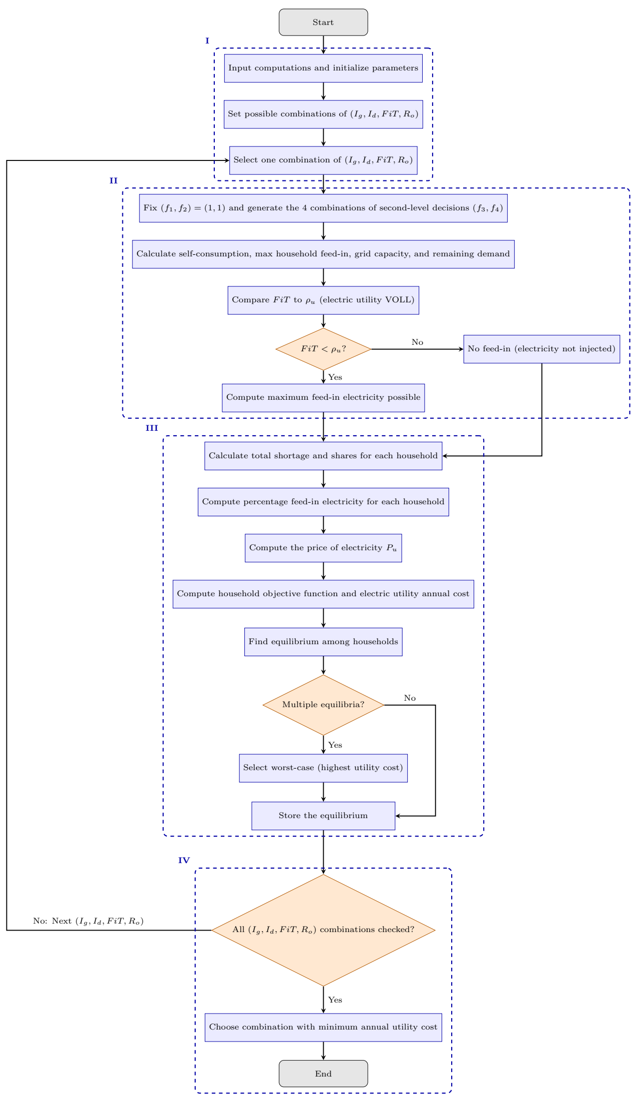


Figure 16: Detailed implementation of the solution approach

E Grid-search boundaries

The bounds of the first-level decision variables used in the numerical grid search are defined below.

Yearly electricity supply from old electric utility capacity, R_o
The maximum yearly supply from old generation capacity, $R_{o,\max}$, is bounded by the yearly potential supply of the existing old power plants:

$$R_{o,\max} = \zeta_o \tag{29}$$

The minimum yearly supply from old generation capacity is set to zero:

$$R_{o,\min} = 0 \tag{30}$$

Electric utility investment in new generation capacity, I_g
The maximum electric utility investment in new generation capacity, $I_{g,\max}$, is determined under the scenario in which households $H1$ and $H2$ self-consume part of their existing PV generation, no additional household category installs PV, no electricity is fed into the grid, no electricity is supplied from old generation capacity, and no shortage occurs. This represents full reliance on new electric utility generation for satisfying the remaining demand. The resulting upper bound is:

$$I_{g,\max} = \frac{\mu_T - \alpha_1 \cdot \theta_1 - \alpha_2 \cdot \theta_2}{\phi_n \cdot \kappa_g \cdot 8760} \tag{31}$$

The minimum investment in new generation capacity is set to zero:

$$I_{g,\min} = 0 \tag{32}$$

Electric utility investment in DRE grid integration, I_d
The maximum investment in DRE grid integration, $I_{d,\max}$, is determined under the scenario in which all strategic household categories participate in the FiT program and the system is able to accommodate their total excess PV generation. Accordingly, $I_{d,\max}$ is defined as the minimum investment required to satisfy:

$$\Gamma(I_{d,\max}) \geq \sum_{i=1}^{4} (1 - \alpha_i) \cdot \theta_i \tag{33}$$

For the linear DRE grid integration function

$$\Gamma(I_d) = \beta_d \cdot I_d + \upsilon_{net}, \tag{34}$$

the corresponding upper bound is:

$$I_{d,\max} = \frac{\sum_{i=1}^{4} (1 - \alpha_i) \cdot \theta_i - \upsilon_{net}}{\beta_d} \tag{35}$$

The minimum investment in DRE grid integration is set to zero:

$$I_{d,\min} = 0 \tag{36}$$

Feed-in tariff, FiT
The maximum feed-in tariff is set equal to the unit running cost of new electric utility generation. This ensures that the compensation paid to households for fed-in electricity does not exceed the unit operational cost of producing electricity from new centralized generation:

$$FiT_{\max} = \xi_n \tag{37}$$

The minimum feed-in tariff is set to zero:

$$FiT_{\min} = 0 \tag{38}$$

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