

Schneider Electric™
Research Institute

System Costs of Electricity

A new baseline for the 21st century economy

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Foreword

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Distributed resources are not a challenge to be managed. They are an asset the system can be built around.

Distributed Energy Resources (DER) at the grid edge are being rolled out rapidly around the world. The reasons for this are well understood: falling equipment costs, often supported by government subsidies, combined with modular and relatively simple installation. Adoption has been further encouraged by higher prices and, depending on where you are, unreliable grid supply.

Rooftop solar initially led the way, but over the past 12–18 months, battery deployments have increased rapidly and, as the authors note, this is the "real game-changer."

Thus, the energy transition is increasingly being shaped by decisions made in homes and businesses. Rooftop solar, batteries and electrification are changing how electricity is produced, consumed and shared, making the relationship between customer investment and system costs a central question for governments and grid operators.

Australia is at the leading edge of this movement. For homeowners with the space and capital, installing rooftop solar accompanied by Behind-the-Meter (BTM) battery storage is now a clear no-regrets move. The latest figures tell the tale. According to Australia's Clean Energy Council, in the 12 months to June 2026, ~320,000 solar installs took place adding ~3.4 GW of generation. The equivalent figures for battery storage were ~457,000 deployments, totalling ~12.9 GWh. As a result, well over a third of Australian households now have rooftop solar and ~7% have a battery storage system.

BTM generation has previously been seen as a challenge for network and system operators with the 'have nots' paying an increasing share of network costs. In extremis, this led to the concept of the utility death spiral. This paper is a valuable contribution to that debate. Its exploration of 40,500 conceptual scenarios offers a useful framework for understanding how falling DER costs, alongside electrification, can support lower electricity costs for all. Importantly, it highlights the opportunity to align new demand with distributed generation and storage, using existing network headroom more effectively rather than considering each development in isolation.

Moving forward, the objective should be to unlock the benefits of customer participation while improving outcomes across the electricity system, including for renters and households unable to install solar or batteries. Distributed resources are not a challenge to be managed. They are an asset the system can be built around. The ability of distributed resources at the grid edge to take pressure off higher voltage parts of the network will become increasingly valuable as data centres and other large loads look for connections and capacity.

There is still much to do – this work is a first word rather than a last one, as the authors acknowledge. The model assumes surplus solar is stored or curtailed, never exported. However, two-way flow is becoming the defining reality, as we are seeing in Australia. Further analysis incorporating solar exports, physical network constraints, local congestion and the allocation of costs and benefits will build on the great foundations shown in this paper and strengthen the work's clear relevance.

I welcome this research as a positive step forward in a complicated and complex debate. It encourages a broader conversation about how countries can integrate distributed resources and growing electricity demand to deliver lasting value for customers and the community, with fairness and affordability at the centre of the transition.



Executive Summary

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Will the rise of rooftop PV and batteries make electricity more, or less, expensive for the economy as a whole?

The world faces today a tsunami of PV and battery (DERs) deployment. A question that arises as a result is whether this deployment will ultimately translate into higher or lower costs of electricity overall. The rationale behind this question has to do with the impact that this transition to DERs entails on the centralized electricity system, notably in terms of utilization. While individual adopters may enjoy early-on benefits from lower costs of electricity from DERs, they may also "free ride" the centralized system at the expense of others.

To answer this question, we develop a Total System Costs model which includes both DERs costs and centralized (utility) system costs. We explore 40,500 scenarios across different load profiles for individual assets and different system mix, with different DERs arrangements with different cost levels.

We find that Total System Costs fall 10% below current levels at world's average costs, a figure which could drop to 40% below current in the 2030s. This optimization proceeds from the continuous decline in DERs costs and from the higher utilization of the centralized system that DERs enable *when combined* with electrification.

The transition toward this new equilibrium rests on the right timing between DERs deployment and electrification. Lack of coordination may indeed cause a temporary rise in costs.

Our findings also suggest that the social optimum is easier to reach than often envisioned, as private optimums naturally lean toward the optimal arrangement at system level.

These results are robust across different asset profiles and system mixes.

The rapid deployment of DERs, combined with electrification of the energy system can provide significant benefits to the economy. We find it could yield an additional income of 0.15–0.8% of GDP. It would also serve as a platform for job creation and resilience.



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Chapter I
Problem Statement

Over a decade ago, the notion that modern rooftop PV and batteries could ultimately provide for a large chunk of electricity demand began to emerge. RMI (2015) demonstrated early on that consumers were better off adopting such systems because of their cost, and that a large consumer-led transition was inevitably on its way.

What happened since proved them right: the amount of solar deployed soared. In 2024, 500 GW of solar panels were installed worldwide, with 40% of it being on rooftops (OECD/IEA, 2025a, 2025b). In the meantime, stationary battery capacity additions exceeded 50 GW in 2024 (BloombergNEF, 2025), a 7-fold acceleration in just 3 years.

And this is nowhere close to slowdown: Walter et al. (2025) from Ember estimate that manufacturing capacity of solar PV is around 2.5 times current demand, and that of batteries above 3 times, with both expanding rapidly.

The potential for rooftop PV and batteries, or distributed energy resources (DERs) as we will refer to them in this paper, is also nowhere close to saturation. 92% of the global population lives in regions endowed with abundant renewable resources (Walter et al., 2025). In a previous study, we estimated that the potential for DERs could exceed 7,500 TWh today (or ~30% of current global electricity demand), a figure that could rise up to 25,000 TWh by 2050 (with building stock expansion and more integrative designs) (Petit, 2022). And these figures are conservative.

Several elements explain this DERs tsunami. First, costs are attractive. Second, these solutions are easy to deploy, seldom require permitting, and offer an easy-to-access energy resource that can be harvested for various purposes. They deploy faster than the conventional grid system. They are consumer-led, hence they are not faced with the inherent complexities of coordinating the large-scale expansion of utility generation and grids. Finally, the concurrent rise of AI-based systems facilitates their integration into modern grids.

An inevitable transition to a more distributed DERs-based system is thus on its way.

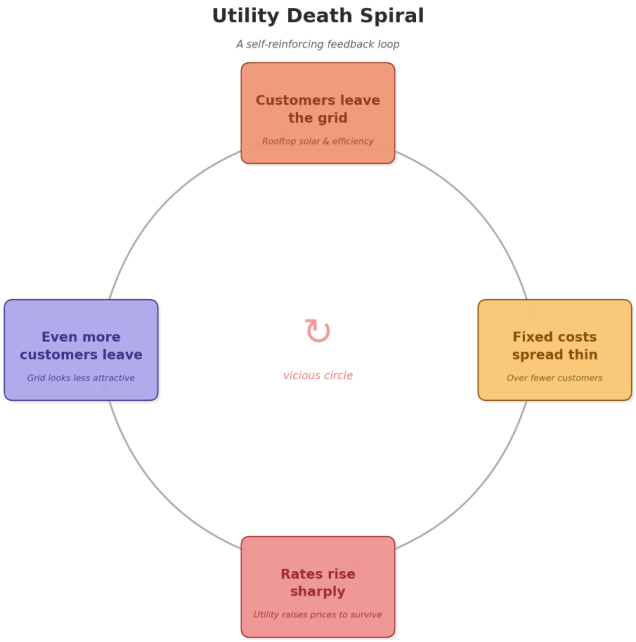
But this transition raises the question of the future fate of the utility grid, a problem coined as the utility death spiral (Exhibit 1). The spiral concept draws on the following line of thought: as more consumers adopt these solutions, the volume of electricity they draw from the centralized system drops; as a large part of centralized costs are fixed in nature (the maintenance of the power lines, poles, substations and to a certain extent generation assets), reduced demand translates into a sharp increase in retail electricity rates for the "remaining" customers, which further accelerates adoption of DERs.

This vicious circle has been widely documented (Castaneda et al., 2017; Say & John, 2021). It also prompted significant work on how to best design retail tariffs to avoid its materialization (Avau et al., 2021; Burger et al., 2020; Hoarau & Perez, 2019; Laws et al., 2017; Schittekatte, 2017). It also led to heated public debates, as in the case of California (California Public Advocates Office, 2024; Solar Rights Alliance, 2024).

The underlying hypothesis behind the death spiral is that **Total System Costs (TSC)** of electricity, while perceived to decrease for consumers who adopt these solutions, do actually increase at a system level since the same infrastructure needs to be kept in parallel of the new system: the same generation capacity needs to be there for periods where solar does not shine, and the grid continues to be required to ensure resilience of electricity access. In short, the grid does not go away. The questions which follow are how to finance it and who to finance it.

To our knowledge, a robust confirmation of this hypothesis is yet to be provided, as it remains to date a contentious object of discussion. The goal of this paper is thus to provide useful inputs to this discussion and answer whether high DERs penetration leads to total system costs that are

Exhibit 1. Utility death spiral



higher, or lower, than today's.

Among numerous attempts to quantify this, the International Energy Agency VALCOE (a refinement of the traditional Levelized Cost of Electricity – LCOE) adds to the costs of renewables the actual "contribution" to grid services, providing a fairer comparison baseline among different generation sources (OECD/IEA, 2020). While it shows highly competitive contribution from renewable energy, its focus is on utility-scale systems. The Energy Transitions Commission establishes that in most geographies, future full system costs of electricity are likely to be significantly lower than current (Energy Transitions Commission, 2025b), but this work is fundamentally centered on the supply side and assumes a near-100% renewable power system by 2050. It thus answers an important yet adjacent question. The Brattle group has also focused on the potential for system utilization improvement in the US and found that utility retail rates could decline by up to 11% thanks to various flexibility measures, including DERs (The Brattle Group, 2025). This work is however fundamentally based on mitigating system congestion in the face of high load growth, rather than on evaluating future costs in high penetration scenarios.

The next chapter briefly introduces the methodology we follow in this paper. Results are presented next, before transition issues are discussed. The paper concludes with key implications.



Chapter II

Modeling Total System Costs

Total System Costs

The metric we follow throughout this paper is **Total System Costs (TSC)**. These costs correspond to the entire expenditure on electricity for the economy (Exhibit 2).

We define these costs as the sum of:

- DERs costs: these include the LCOE of rooftop PV and the levelized cost of storage (LCOS) of batteries. DERs costs represent the combination of these installed costs times the energy produced and/or discharged.
- Centralized costs: these include both variable and fixed costs of the centralized utility grid
  - Variable generation and grid costs, which are a function of the energy flowing through the system.
  - Fixed generation and grid costs, which are applied regardless of the amount of energy supplied by the system.

Our baseline assumption for centralized costs is a benchmark $US160 per MWh (excluding tax), including $90 per MWh generation (45% fixed), and $70 per MWh grid (85% fixed), translating into $US60 per MWh of variable costs and $100 per MWh of fixed costs.

We develop a system cost simulator in R program to analyze various scenarios and measure Total System Costs (TSC) in each of them. This simulator integrates both DERs and the centralized infrastructure.

We first build a conceptual physical network, made up of a mix of assets with different load profiles, aggregating into a baseline system load duration curve (SLDC).

We further apply DERs to these assets (PV and batteries). The control algorithm of DERs focuses on minimizing peak levels and flattening the load profile of each asset. As each asset's load profile changes, the system load duration curve is also transformed. Because the algorithm focuses on reducing peak demand, headroom is generated at the system level. This headroom can be further "backfilled" with additional electricity demand coming from new loads (e.g., EVs, data centers), which changes the utilization of the centralized system.

Exhibit 3 provides a simple representation of the resulting mechanisms of TSC formation. Unitary costs of DERs contribute to define the sizing of DERs at asset levels. The resulting DERs costs affect the levelized cost of production of energy, but the penetration of DERs may also require the provision of additional system services to balance the system and ensure reliability of supply.

The sizing of DERs also defines the opportunity for backfilling. This increased demand can occur on sites where headroom has been created (e.g., additional demand from air conditioning or EVs in buildings). For these cases, the impact on costs is minimal: there is no significant need for grid reinforcement, as DERs continue to keep load within peak limits (and flat), a potential which we confirmed in previous research (Minier, 2025). Yet, increased demand can also occur on new sites: new facilities that are connected to the network (e.g., data centers). In such a case, connection to the grid entails further capex investment. Finally, existing sunk fixed costs remain stable in volume and are a function of the new system utilization achieved.

Total System Costs represent the sum of both these channels (Equation 1). They are expressed in dollars per MWh and can be further compared to a baseline centralized system, with no DERs (Equation 1 is a simplification, see Appendix A for a more detailed description of the actual calculation).

Exhibit 2. Total System Costs

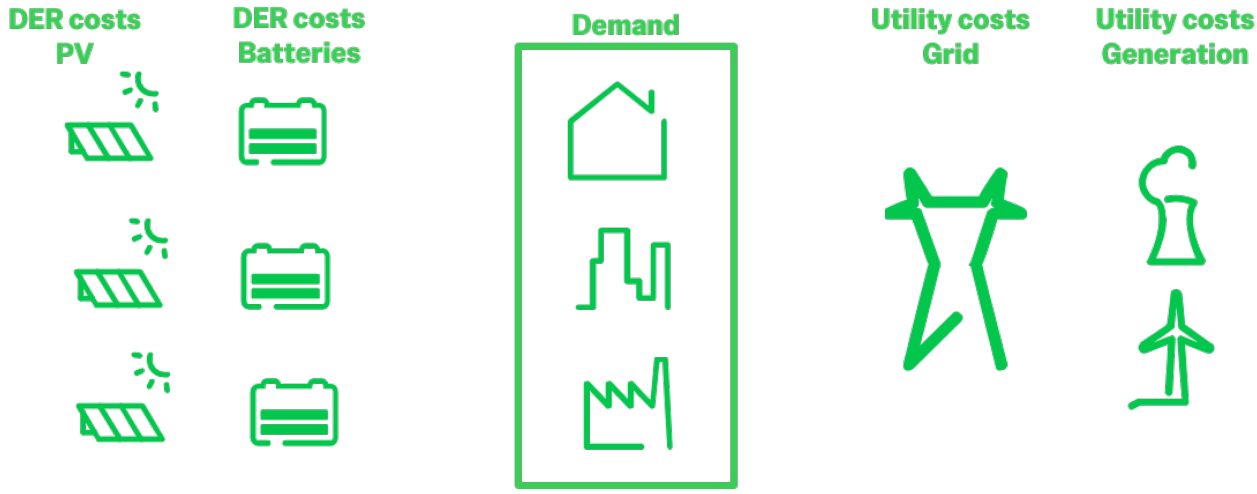
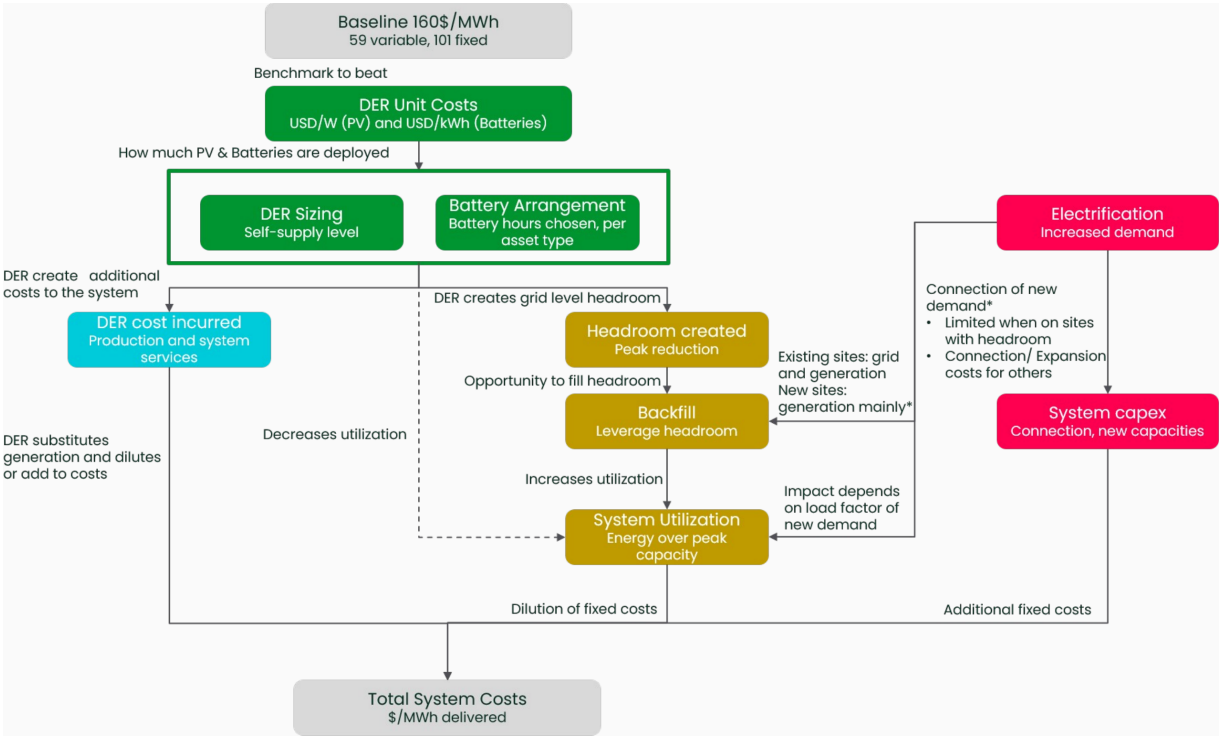


Exhibit 3. Mechanics of TSC formation



(*) When demand occurs on sites where (and within) headroom has been enabled, it requires limited to no capex, and naturally dilutes both generation and grid fixed costs. When demand occurs on new sites (still within aggregated headroom), it requires connection capex. It will dilute generation costs, and in part fixed costs depending on the share of existing grid being utilized.

$$\text{TSC} = \text{DERs cost} \times \text{self-consumption} + \left(\text{variable centralized costs} + \frac{\text{sunk fixed costs}}{\text{energy ratio}} + \text{connection capex}\right) \times (1 - \text{self-consumption}) + \text{system services} \quad \text{(Eq. 1)}$$

Assumptions

Five key categories of assumptions influence results on TSC. They include assumptions on load demand, DERs sizing, backfill level, DERs and centralized costs.

In the conceptual network, 3 different types of load are represented (residential, service building, and industry), each with its own daily and annual profile (Exhibit 4). We take specific assumptions on those and study the sensitivity of the results to changes in load profiles (assuming non-electrified and electrified heating).

The aggregation of that demand provides a System Load Duration Curve (SLDC) (Exhibit 5). We consider different possible asset mix, to represent different regional archetypes (a building centric case with 75% of demand from buildings, representative of western economies; and a balanced mix with 60% of demand from buildings, consistent with more industrialized countries, e.g., China).

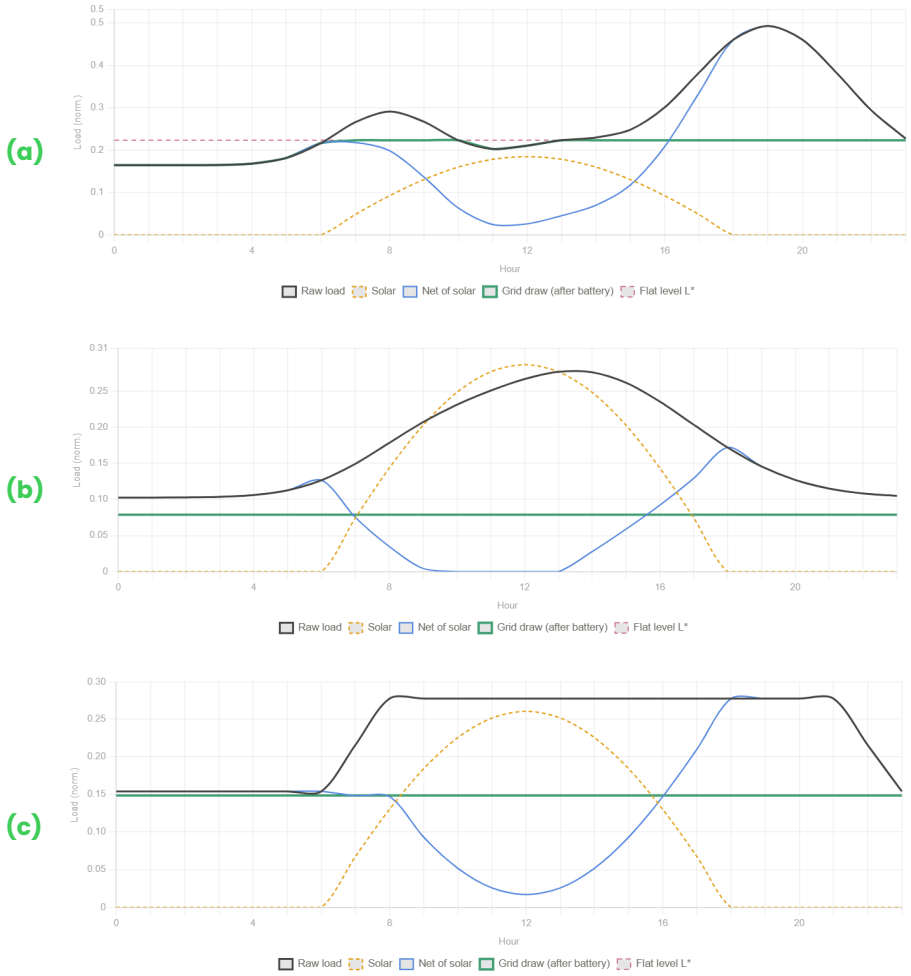
The sizing of DERs breaks down between PV and batteries. For PV, we consider different levels of penetration for each asset type and take 3 scenarios, considering a low, medium and high penetration cases. For batteries, we consider a range of options measured in hours of peak demand, ranging from 0 to 8h (with 125 possible combinations across the three assets).

DERs costs are also subject to assumptions. Based on the literature, we take 3 specific cases: current US costs, current (average) world costs, and we project a possible cost point for the 2030s.

Finally, as DERs enter the system, they create headroom at system level (Exhibit 5). This headroom can be "backfilled" by electrification, which leads to a change in system utilization, and dilution of existing fixed sunk costs. Additional costs need however to be accounted for: they include system services (for reliability) and connection capex costs for new demand requiring connection to the grid. We take 3 specific assumptions for the former. For the latter, we distribute the new load between existing sites (where headroom has been created), and new sites (e.g., data centers, new facilities), where specific connections at transmission or distribution level are required.

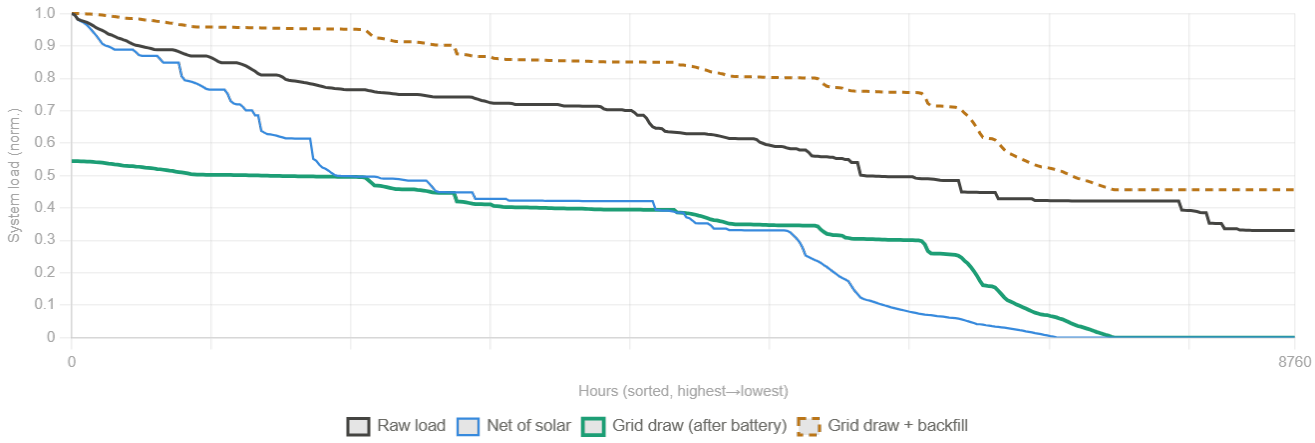
TSC are measured from the combination of these assumptions. In total, 40,500 scenario runs are realized. All assumptions considered in this report are synthesized in Exhibit 6. Details on methodology and assumptions are provided in Appendix A.

Exhibit 4. Illustrative examples of load profiles in the model



Dark line corresponds to the original load; yellow dashed line to the production of PV; blue line to the grid load following integration of PV; green line to the grid load after PV and batteries (a large battery size is selected here). (a) corresponds to a residential building, non-electric with low PV self-supply, on a winter day. (b) corresponds to a service building, non-electric with medium PV self-supply, on a summer day. (c) corresponds to an industrial building with medium PV self-supply, on a summer day.

Exhibit 5. Illustrative example of load duration curve in the model



Dark line corresponds to the original load; blue line to the grid load following integration of PV; green line to the grid load after PV and batteries (for a given select size of battery); dashed orange line to the grid load after all previous steps and backfilling. This illustrative example corresponds to a building centric configuration with non-electric assets, in a scenario with high PV self-supply and 2h of batteries on each asset type.

Exhibit 6. Key assumptions summary

Category	Assumption	Details	# of cases
Load demand	Load profile	Conceptual system based on a mix of 3 types of assets: residential, service and industry. Each asset has a specific annual / daily profile. 2 cases considered: non-electric load and electric load (electrified heating).	2
	System profile	Conceptual system based on a mix of assets. 2 cases considered: building centric (50% residential, 25% service, 25% industry), closer to Western profiles, and balanced (40% residential, 20% service, 40% industry), closer to e.g., China.	2
DER sizing	PV sizing	3 cases considered for PV penetration: low / medium / high, measured in level of self-supply (vs existing demand). Low: 30% for residential/services, 10% for industry Medium: 60% for residential/services, 20% for industry High: 90% for residential/services, 30% for industry	3
	Battery sizing	Different battery arrangements possible at site level, measured in number of hours of peak demand (peak hours capacity). 5 cases for each asset: 0h–2h–4h–6h–8h, leading to $5^3 = 125$ combinations.	125
Backfill	Electrification	Increased electricity demand to fill the headroom created by DERs. 3 cases considered: 0% backfill (no change in demand), 50% backfill (of the headroom created), 100% backfill. All backfill is met with demand at 0.85 load factor (assuming flat loads and/or load integrating DERs).	3
DER costs	PV	Focus on installed costs (not components alone). 3 scenarios reflecting the specific US situation, today's world average (excluding the US) and expected 2030s levels. Current US: $US3 per W for residential and $US1.8 per W for service and industry Current World: $US1 per W for residential and $US0.7 per W for service and industry 2030s: $US0.5 per W for residential and $US0.4 per W for service and industry	3
	Battery	Similar to PV, 3 cost scenarios. Current US: $US1,000 per kWh for residential and $US500 per kWh for service and industry Current World: $US700 per kWh for residential and $US350 per kWh for service and industry 2030s: $US150 per kWh for residential and $US100 per kWh for service and industry	
Centralized costs	System services	System services may increase centralized costs for reliability purposes (e.g., inertia, balancing). 3 cases estimated with variation from $US0–6–12 per MWh of additional cost.	3
	Connection capex	Additional connection capex depends on where extra demand is located. 50% of extra demand assumed to be on existing sites where headroom is created, i.e., at no additional cost (Minier, 2025). 25% of extra demand as new load on transmission level ($US250 per kW of connection) and 25% on distribution level ($US700 per kW).	1



Chapter III

Total System Costs: More or Less Expensive?

Total System Costs with high DERs well below current

Benefits are significant

Exhibit 7 provides the minimum Total System Costs (TSC) which can be reached across different cost paradigms. They assume non-electric loads and a building centric system (we review variations from this baseline further down). These costs represent the minimum achievable, across a wide range of possible battery arrangements and PV sizing, and backfill levels.

Finding 1

Under current world cost conditions, TSC are 10% below current levels. They further fall to -40% under 2030s cost conditions. In the US, however, they are for now 20% above current.

This finding suggests that, outside of the US where installed costs are significantly higher than in other geographies, the transition to a system with high penetration of distributed resources is economically beneficial. Considering electricity expenses at 1.5–2% of global GDP (EIA, 2024; Global Petrol Prices, n.d.), these savings translate into an additional income ranging around 0.15% of GDP, increasing up to 0.8% of GDP in the 2030s.

Results are robust to different system configurations

Exhibit 8 shows how these minimum TSC evolve when considering alternative profiles and mix, i.e., electrified load profiles and different asset mix. Across all configurations, minimum TSC vary by 4–17%.

Finding 2

Optimal TSC do not vary by more than 17% when considering different load profiles and system mixes. Findings on TSC thus remain robust across system configurations.

Note 1: these results depend on the assumed seasonality of solar generation. As the study is global, the model uses a generic sinusoidal profile with a summer-to-winter ratio of 1.8:1. This corresponds closely to observed seasonality in subtropical high-irradiance markets, sitting between Mexico (~1.6:1) and Australia (~2.1:1), the latter being the market with the highest rooftop PV penetration globally. We test sensitivity across the full observed range, from northwest India (1.6:1) to Germany (7:1). Minimum TSC vary by under 2% in the current US case, under 8% in the current world case, and up to ~20% in the 2030s case where DERs deployment is greatest. Conclusions are unchanged: the 2030s case remains well below the centralized benchmark at every seasonality tested.

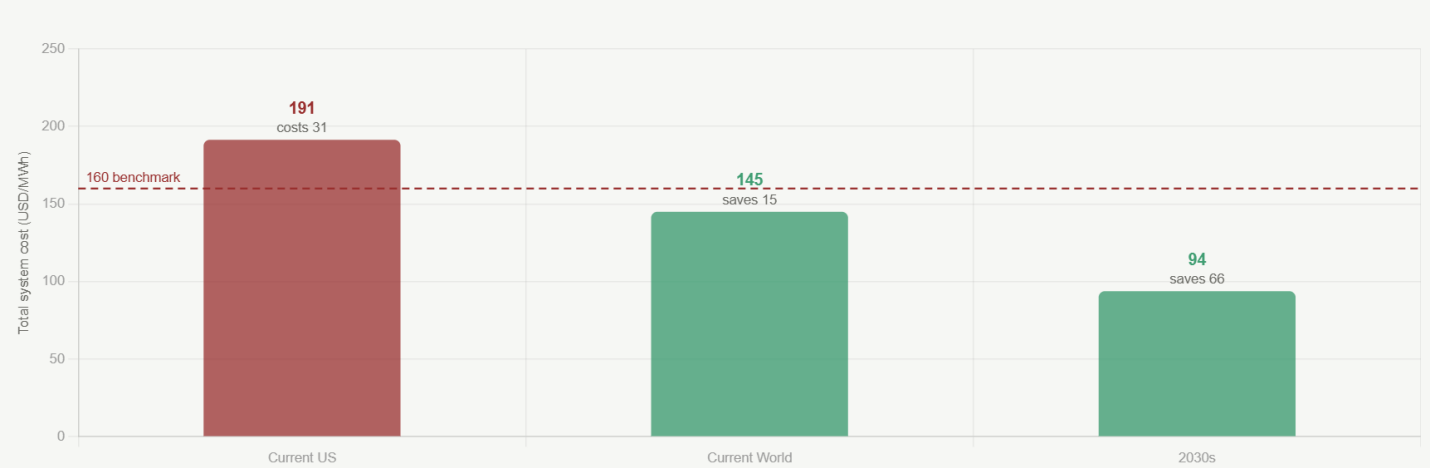
Note 2: central system costs may also vary $US0–12 per MWh. In Exhibit 7 and Exhibit 8, we have considered the central case ($US6 per MWh). Changes in system service costs do not materially affect the conclusions. In the remainder of the paper, we will focus only on building centric, non-electric system configurations, and central system service costs.

Results are highly sensitive to battery arrangements

Exhibit 9 shows the breakdown of TSC across contributions from DERs and centralized costs, as well as the variation in TSC depending on battery arrangements, i.e., the choices of battery hours selected by each asset type (125 configurations).

Crucial to minimizing the TSC are, first, DERs costs and,

Exhibit 7. Minimum TSC of electricity across various cost points



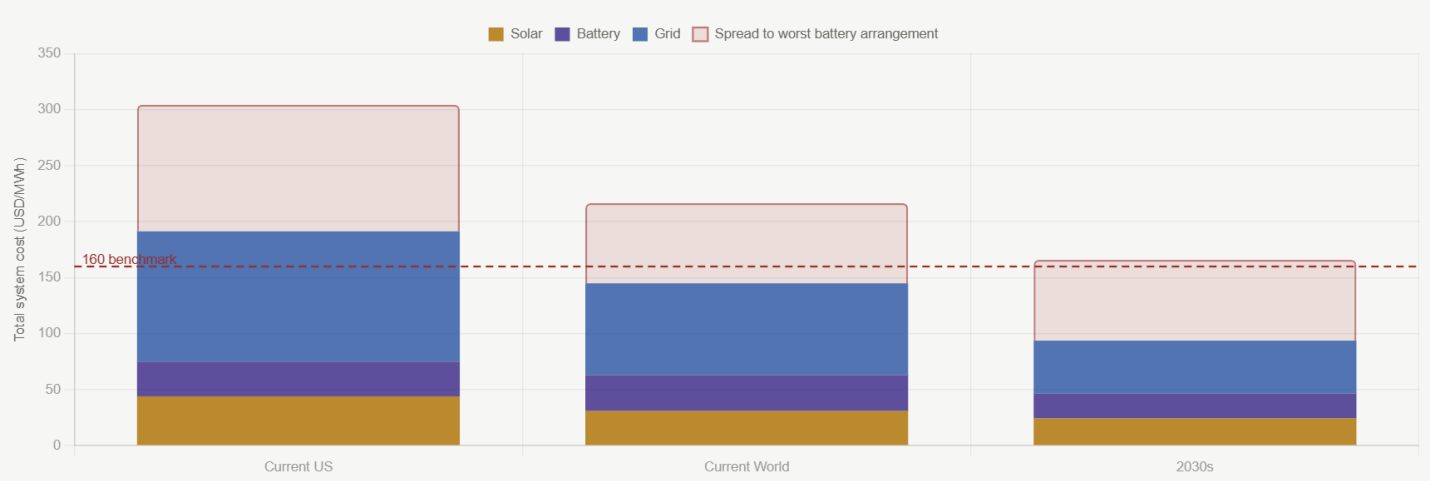
Minimum overall blended price (searching all battery arrangements) by cost scenario. Green below 160, red above. All self-supply and backfill configurations considered. System configuration: building centric, non-electric, central system service costs.

Exhibit 8. Evolution of optimum system costs across different archetypes

Configuration	Current US	Current World	2030s
Building-centric · non-electric	191	145	94
Building-centric · all-electric	194	152	103
Balanced · non-electric	186	147	102
Balanced · all-electric	188	154	110

Best achievable TSC for every configuration. Columns show cost level; rows show system configuration. Each cell shows the minimum TSC achievable in this configuration. Green below 160, red above. System configuration: central system service costs.

Exhibit 9. Minimum TSC breakdown



Blended price decomposition (solar LCOE + storage LCOS + on-grid) for the cost-minimizing battery, across cost assumptions. All backfill and self-supply levels configurations considered. Red shaded cap = range to worst battery arrangement. Dashed red = 160 baseline. System configuration: building centric, non-electric, central system service costs.

second, the system utilization after DERs deployment and backfill, and the resulting centralized system costs in dollars per MWh. As more DERs are being deployed on the system, their contribution to TSC increases. This contribution reduces significantly over time as costs go down. As penetration increases, system utilization is further improved through backfilling, leading to lower centralized costs as a result (in dollars per MWh).

Non-optimal battery arrangements can, however, lead to higher TSC because too much or too little DERs are deployed (with no significant improvement on utilization). This non-optimal choice may cause costs to arise significantly: in the US cost scenario, from +20% (optimal) to +90% (worst case); in the world cost scenario from -10% to +35%; and in the 2030s cost scenario from -40% to +3%. We will come back to this in the discussion on transition dynamics. The variation is all the more important as battery costs are high.

Finding 3

Optimal choice of DERs penetration has a significant impact on TSC. While this has limited impact on conclusions in 2030s cost scenarios, it may raise TSC above the benchmark in current cost scenarios.

Who pays what?

Each asset is faced with a different cost point, depending on the amount of DERs deployed on site and the resulting energy drawn from the grid (i.e., the exposure to centralized system costs). We refer to them as Asset System Costs (ASC). TSC are the weighted average of ASC, considering the mix of residential, service and industry assets.

Exhibit 10 shows that, in the optimal case, service and industry benefit from the transition across all cost conditions.

In the current US case, residential bears a significantly higher cost due to the costs of DERs. As costs go down (e.g., 2030s levels), all asset types benefit. Yet, this reduction in ASC is less favorable to industry. This has to do with the lower potential for DERs deployment in industry, which as a result benefits less from these lower costs and remains more reliant on energy drawn from the grid.

Finding 4

Residential is more exposed to higher costs when DERs costs are high. As costs go down, industry relative TSC decrease at a slower pace. Service buildings costs always score the lowest.

Complex mechanics of change

The substitution-dilution effects define the evolution of TSC

Following Exhibit 3, two main effects define the evolution of TSC: a substitution effect (DERs *substitute* delivered generation through self-consumption) and a dilution effect (evolutions in system utilization affect the *dilution* of fixed costs).

Exhibit 11 provides a perspective of each contribution on TSC against different backfill assumptions and for each cost configuration. When DERs costs get low enough (i.e., outside of the US configuration), substitution of centralized supply always generates savings on TSC, their level depending on overall DERs sizing.

The effect on dilution, however, depends on backfill levels (i.e., electrification). 100% backfill of the headroom provides savings while lower levels of backfills translate into additional costs as the system utilization is degraded.

Finding 5

The optimization of TSC with high DERs penetration only works when coupled to parallel growth in electricity demand, i.e., electrification of the energy system.

The bulk of the TSC reduction (in current world's costs and 2030s costs) comes from substitution effects, rather than dilution effects. This is because DERs are very competitive compared to benchmark delivered energy (Exhibit 12).

Finding 6

The bulk of TSC optimization comes from substitution effects, while backfilling enables to limit the negative effect on grid utilization.

Going deeper

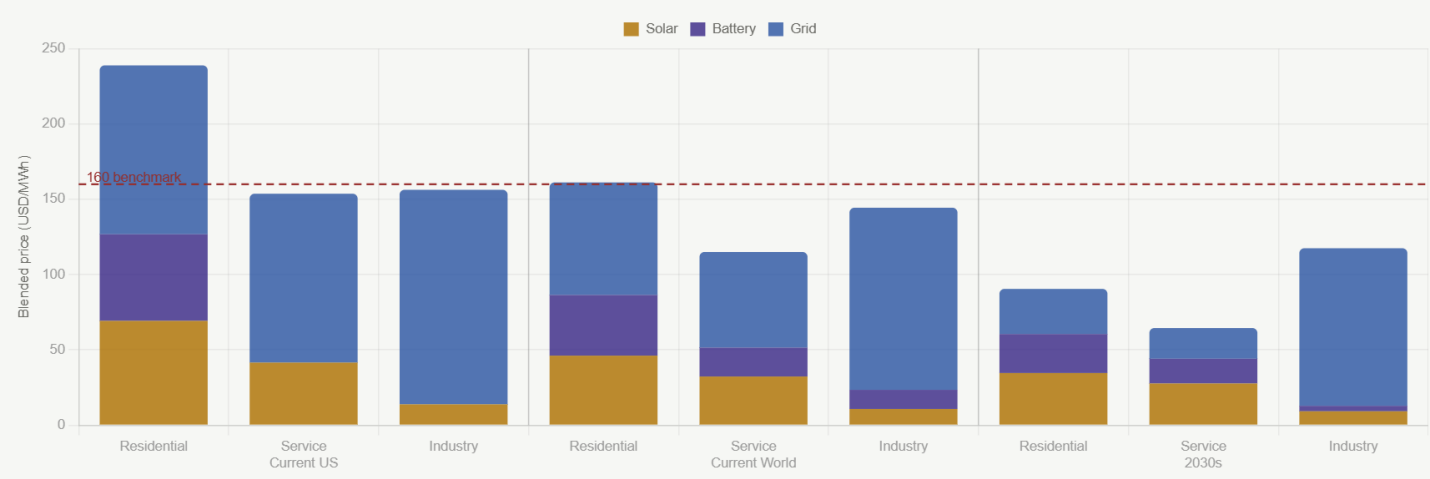
Substitution is a function of DERs costs. When PV alone is deployed, the cost of PV is affected by the level of curtailment of solar, which can reach up to 40% in cases of high penetration. The battery contributes to reducing that curtailment. In scenarios of high battery deployment, curtailment can be cut down to zero, which optimizes DERs costs. Yet, it adds to them through greater battery sizing (Exhibit 12).

The battery system does more than just substituting generation, however. The flattened load profile provided by DERs enables backfilling, hence system utilization improvements, and leads to a dilution of fixed costs in $US per MWh. High backfill levels (i.e., well above 50%) are crucial to generate savings (Exhibit 13).

Both channels and their dynamics can be reconciled in the TSC, using Equation 1.

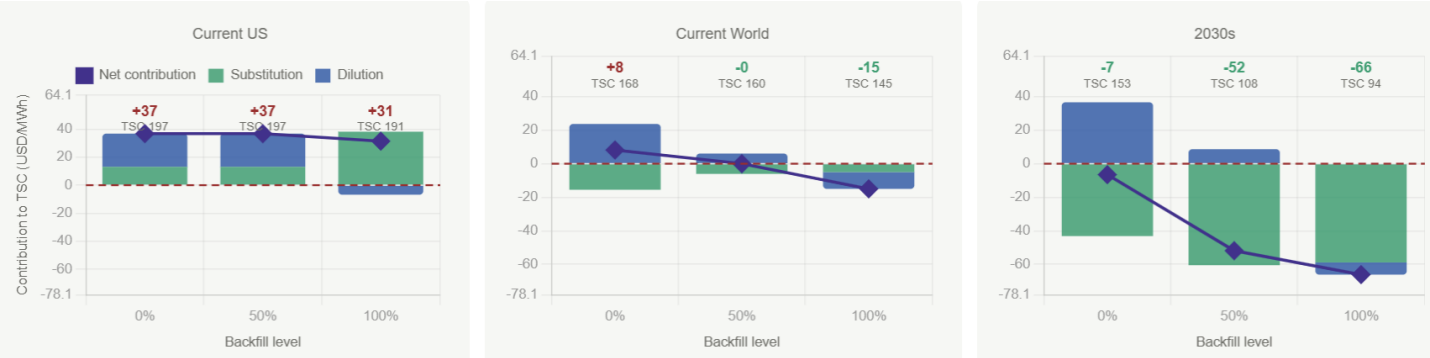
- DERs substitute grid-drawn electricity and come at a cost (function of its penetration and unitary costs) which is today already competitive (outside of the US) and will get increasingly compelling. This is because the energy supplied does not need to travel through the grid.
- The "new" cost of grid-drawn electricity is a function of

Exhibit 10. Asset System Costs, at the optimal TSC



Asset-level price decomposition (solar LCOE + storage LCOS + on-grid) for the cost-minimizing battery, across cost assumptions. All self-supply levels configurations considered, 100% backfill considered. System configuration: building centric, non-electric, central system service costs.

Exhibit 11. Substitution & dilution of costs



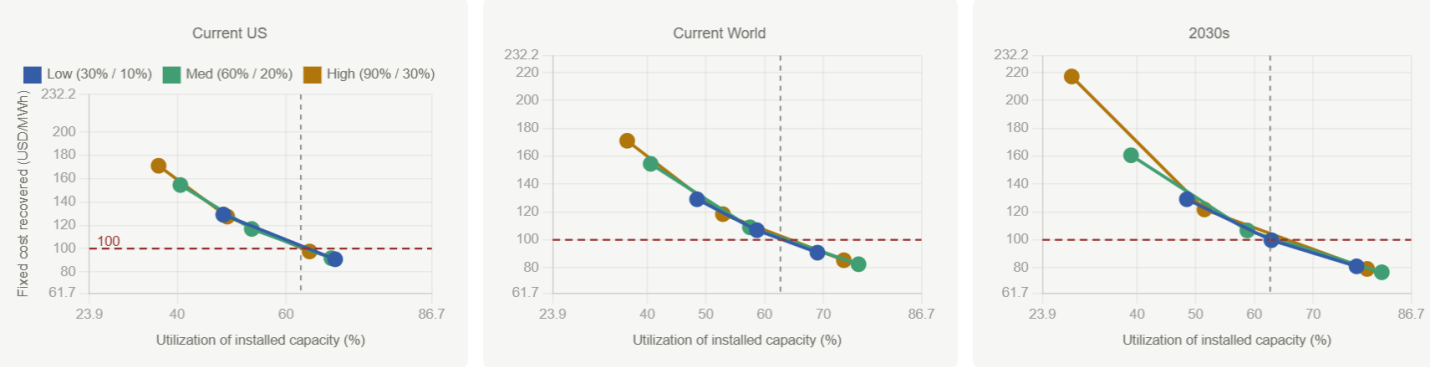
Contribution from substitution in green (DERs displaces grid electricity) and dilution in light blue (effect on grid costs). Combined effect (straight line, dark blue) and overall effect on TSC (above) as a saving vs the $US160 per MWh benchmark. Left box: current US costs; center box: current world's costs; right box: 2030s costs. Within box, left: no backfill; center: 50% backfill; right: 100% backfill. System configuration: building centric, non-electric, central system service costs.

Exhibit 12. DERs substitution



Combined DERs costs (LCOE for PV and LCOS for battery) for each self-supply level at the TSC-minimizing level. Orange: PV cost alone; dashed blue: effect of battery on curtailment; blue: PV and battery (including cost of battery). Left: current US costs; center: current world costs; right: 2030s costs. System configuration: building centric, non-electric, central system service costs. Backfill 100%.

Exhibit 13. Fixed costs dilution



Fixed cost impact depending on enabled backfill (bullets correspond to 0%, 50%, 100% backfill). Compared to the fixed cost benchmark of $US100 per MWh. Minimum achievable for each self-supply level (blue: low, green: medium, orange: high). Left: current US costs; center: current world costs; right: 2030s costs. System configuration: building centric, non-electric, central system service costs.

the system utilization of the system. When backfill materializes (i.e., electrification), system utilization is improved, which contributes to diluting sunk fixed costs into a larger pool of energy delivered. With limited additional capex and system services costs, overall centralized system costs stabilize or decrease.

Service assets contribute significantly to TSC optimization

Exhibit 14 provides a detailed perspective on substitution-dilution effects at the asset level (assuming 100% backfill – conclusions are robust to other assumptions). Residential naturally shows the greatest variance, as it represents a large share of the system mix, hence affecting TSC in proportion.

Yet, service buildings emerge as a key contributor of TSC improvement. This is due to the high share of self-consumption driven by DERs given the specific load profile of these assets (daily consumption peak). Industry contributes less given lower DERs penetration and is in practice the asset most sensitive to the evolution of grid-level system costs.

Exhibit 14. Contribution to TSC optimization at asset level



Contribution from substitution in green (DERs displaces grid electricity) and dilution in light blue (effect on grid costs). Combined effect (straight line, dark blue) and overall effect on TSC (above) versus the $US160 per MWh benchmark. This graph shows what each asset class causes on the overall TSC evolution, not what it incurs in costs (which depends on how much electricity is drawn from the grid). Left: current US costs; center: current world costs; right: 2030s costs. For each cost configuration, residential (left), service (center) and industry (right) contributions are plotted. Backfill at 100%. System configuration: building centric, non-electric, central system service costs.



Chapter IV

Transition to High DERs Systems: Bumpy or Straightforward?

Until now, all results have been drawn from equilibrium states. Yet, the transition toward these equilibria will depend on the dynamics of change in DERs deployment, electricity demand and costs. TSC will naturally follow these dynamics.

Timing between DERs and electrification

When not coordinated, costs may temporarily go up

Exhibit 15 suggests a conceptual model of change, following three different scenarios which account for whether DERs penetrate the system faster than electricity demand (DER-first), whether electricity demand grows before headroom can be created from DERs (demand-first), or both grow at a coordinated pace.

In the DER-first scenario, DERs deploy at scale, creating headroom in the power system. Since this headroom is not met by rising electricity demand at the beginning (backfill), prices go up as new capacities are deployed and the system utilization is lowered. When electricity demand finally picks up, TSC begin to decline.

In the demand-first scenario, electricity demand increases, requiring investment in new centralized capacities. As DERs are not deployed, the load factor is similar to (or lower than, e.g., air-conditioning) current. If these new capacities involve dealing with congestion on existing networks or require grid reinforcement (e.g., EVs in buildings), TSC go up. When DERs come online, the virtuous circle of backfilling can be put in play, but only on new demand: existing investments are sunk.

In the coordinated scenario, both advance together, leading to a more favorable decline in TSC.

This conceptual approach suggests that when coordination is missing, costs are likely to go up, at least temporarily.

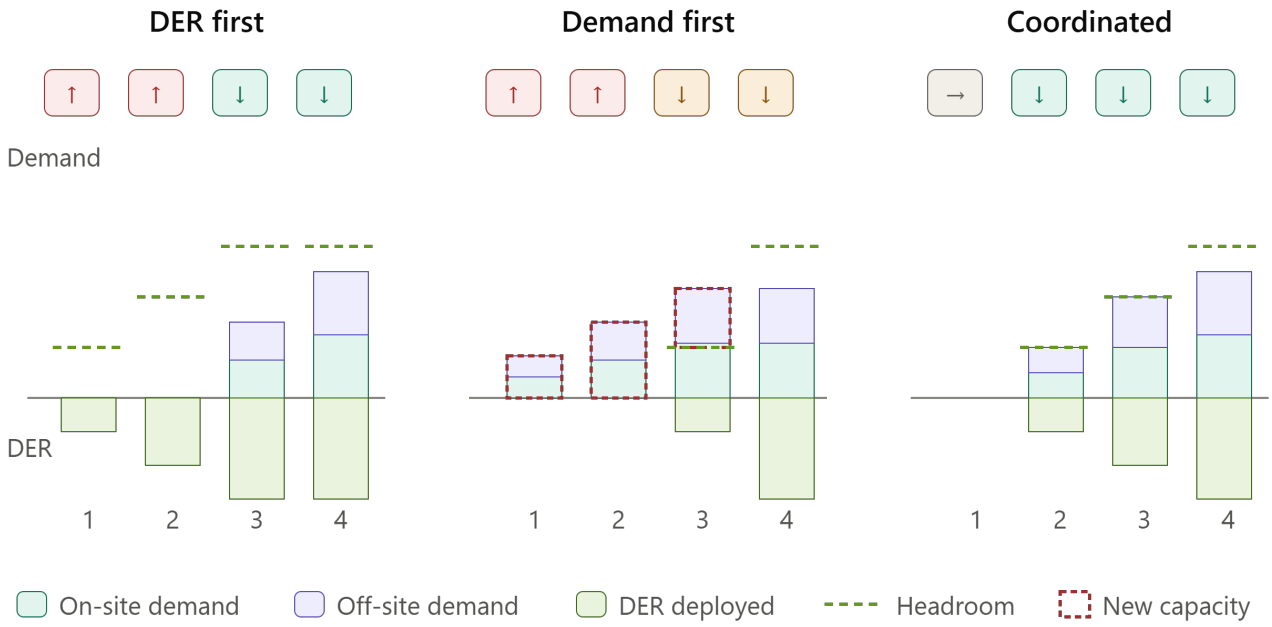
Exhibit 16 extends this conceptual approach and leverages the model to build a numerical estimate of how such dynamics translate into TSC changes. These scenarios are essentially illustrative as they are pushed to show sizeable numerical differences. Details on key assumptions are provided in Appendix B.

In the demand-first scenario, electricity demand grows rapidly, but DERs only emerge at scale in the second half of the 2030s. The result is an increase in TSC due to grid reinforcement needs and large capex investment to cope with uncontrolled demand growth (e.g., EVs adding to peak demand, new facilities requiring connection, etc.). When DERs deployment kicks in (end of the 2030s), costs begin to decline as new demand can now leverage the new backfill potential, rising system utilization as a result.

In the DER-first scenario, DERs deployment starts immediately and reaches its full potential in 2045. Demand only starts to accelerate from 2035 onward. Within this gap-period, TSC increase as costs pile up without backfilling. When backfilling finally kicks in, demand increases contribute to improving system utilization, lowering TSC. Because DERs costs improve very rapidly across the period, the temporary increase in TSC remains lower than for the demand-first scenario. This difference has mainly to do with a substitution effect stronger than the dilution effect, and with DERs costs showing high learning rates, compared to system capacity investments.

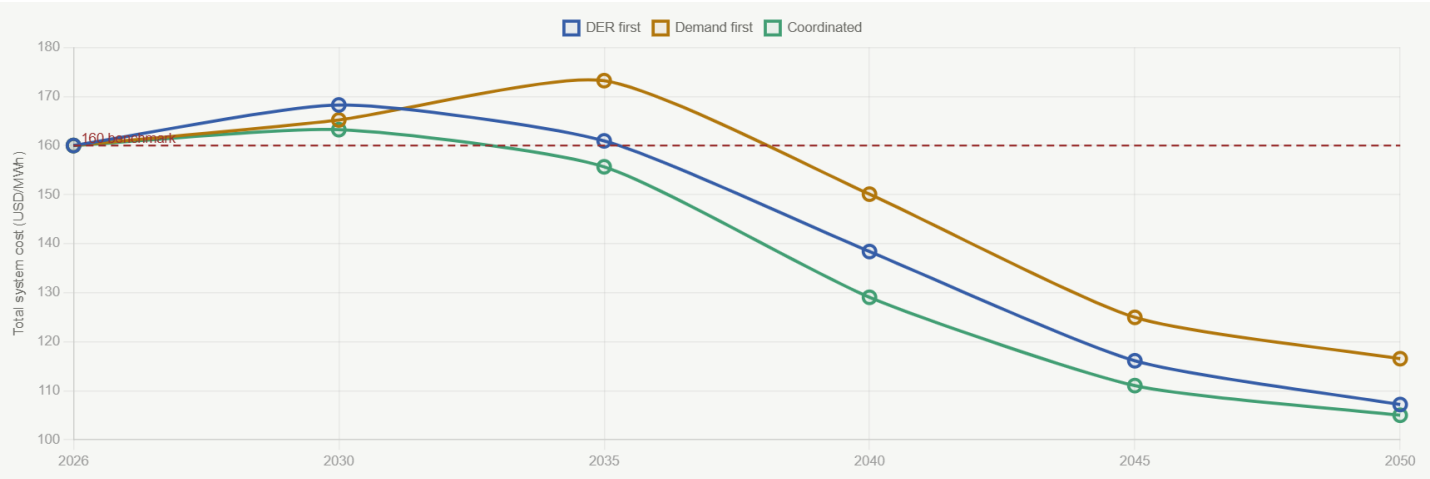
In the coordinated scenario, both start immediately and they ramp up more progressively. The more DERs, the more electrification, leading to a virtuous circle of TSC optimization and the lowest TSC overall across all three scenarios,

Exhibit 15. Timing between DERs & electrification



Conceptual step-wise approach of how TSC evolve depending on dynamics of DERs penetration (below) and electricity demand evolution (above). Headroom (dashed green) shows the amount of capacity for backfilling created from DERs deployment. Demand areas circled in dash red account for the additional demand that increases the original peak due to lack of backfill potential. Three scenarios presented: DERs deployment with lagging electricity demand (left); electricity demand growth with lagging DERs supply (center); and coordinated response (both advancing at the same time).

Exhibit 16. DERs and electrification transition scenario



Minimum TSC achievable across 3 transition archetypes (blue: DER-first, orange: demand-first, green: coordinated). System configuration: building centric, non-electric, central system service costs.

since limited wasted investment has occurred (e.g., grid reinforcement for specific loads which could have been avoided from backfilling).

While illustrative, this numerical analysis confirms the intuition that non synchronized deployment of DERs and electrification lead temporarily to an increase in TSC. This finding is crucial as dynamics of change between DERs deployment and electrification are likely to differ:

- DERs deployment is further accentuated by reductions in costs (from learning rates) and high retail electricity prices.
- Electrification of demand is contingent on new demand sources stemming from new products (e.g., EV, air conditioning) or investment (e.g., industry, data centers), and competitive retail electricity prices.

> **Finding 7**
> **DERs without electrification and electrification without DERs both lead to inefficiency compared to the optimal TSC (although the effect is much lower when DERs precede demand). The transition to a high DERs power system may thus face temporary increases in TSC before they fall over time.**

Different regions will face different change pathways

The intricate and complex nature of such changes will naturally differ from one region to another (Exhibit 17). While a detailed analysis of regional differences is beyond the scope of this paper, it is enough to say that some regions experience rapid DERs deployment with limited growth in electricity demand (e.g., Europe), and these naturally face rising pressure on centralized system costs. Conversely, some regions see rapid growth in demand (e.g., some US states) with (still) DERs deployment lagging, translating into rising retail electricity prices.

In Europe, the emerging demand for new loads such as EVs, air-conditioning, data centers can contribute to mitigate this rise in costs, provided demand is not further depressed by a decline from other demand sources (e.g., industry) and DERs continue to accelerate (with batteries). In the US, the rapid growth in demand currently observed may significantly benefit from an acceleration of DERs.

Exhibit 17 does not tell the full story, however. Some regions show supply overcapacity (e.g., France), which "buys time" for increased electrification and increased centralized system utilization. Many regions also need to invest regardless in their grid for reinforcement and modernization (e.g., the US), which will add to TSC.

> **Finding 8**
> **Regions differ in their dynamics of DERs deployment and electricity demand growth. They also differ in terms of the nature and state of their current centralized system. These will all affect the evolution of TSC in the short term.**

Reaching the optimum

Social and private optimums are distinct equilibria

So far, we have mostly focused on TSC, i.e., total costs incurred from the entire system. In practice, different asset types face different costs, i.e., different Asset System Costs (ASC). Residential buildings, service buildings and industrial assets deploy different DERs systems and draw different energy volumes from the centralized system. Their cost equations (ASC) thus differ.

If each asset controls the amount of DERs (PV and batteries) it installs, it does however have to cope with the centralized or on-grid electricity cost resulting from the combined optimization generated by all assets deploying DERs (and the aggregated level of backfill).

Exhibit 18 illustrates this for industry. The minimum ASC in the configuration displayed is $US142 per MWh, with a 2h battery dispatch. Yet, the industry asset owner only enjoys this lower ASC provided service asset owners select a 2h battery and residential a 4h battery. In case they choose a different arrangement, industry ASC may reach up to $US178 per MWh (a case where service and residential deploy no batteries).

This pattern is reproduced for each asset type and thus translates into a level of uncertainty on TSC.

We further define two concepts: the *social optimum*, i.e., the minimum TSC achievable (what this paper has been concentrating on thus far); and the *private optimum*, i.e., the configuration resulting from each asset owner selecting the most favorable arrangement for themselves, based on key assumptions they make on others' choices.

Private rational interests converge toward the social optimum

The question is thus the extent of inefficiency raised from lack of social optimum convergence from the individual choices made by each asset owner. Exhibit 19 shows, for each DERs cost assumption, the actual deliberation of each asset owner (residential, service, industry). Each asset owner can select a level of self-supply and a battery sizing. He selects *rationally* the minimum ASC he can reach. In Exhibit 19, this selection is done by assuming other asset owners select the least favorable DERs arrangement to him.

Under these conditions and for current US costs, all asset owners select low self-supply and no battery. This is the private optimum, and it leads to TSC of $US197 per MWh. This is $US5 per MWh above the social optimum, i.e., negligible.

For current world costs, asset owners select a different self-supply level and various battery arrangements. This translates into private optimums of $US151–168 per MWh (depending on the final state of self-supply), ranging $US0–13 per MWh above the social optimum. In this scenario, the

Exhibit 17. Regional archetypes

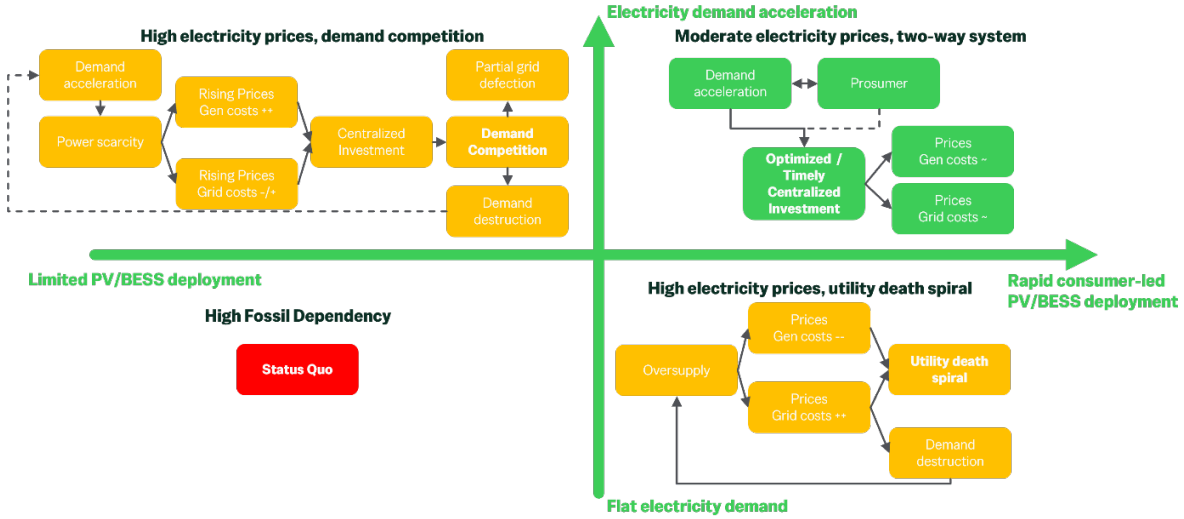
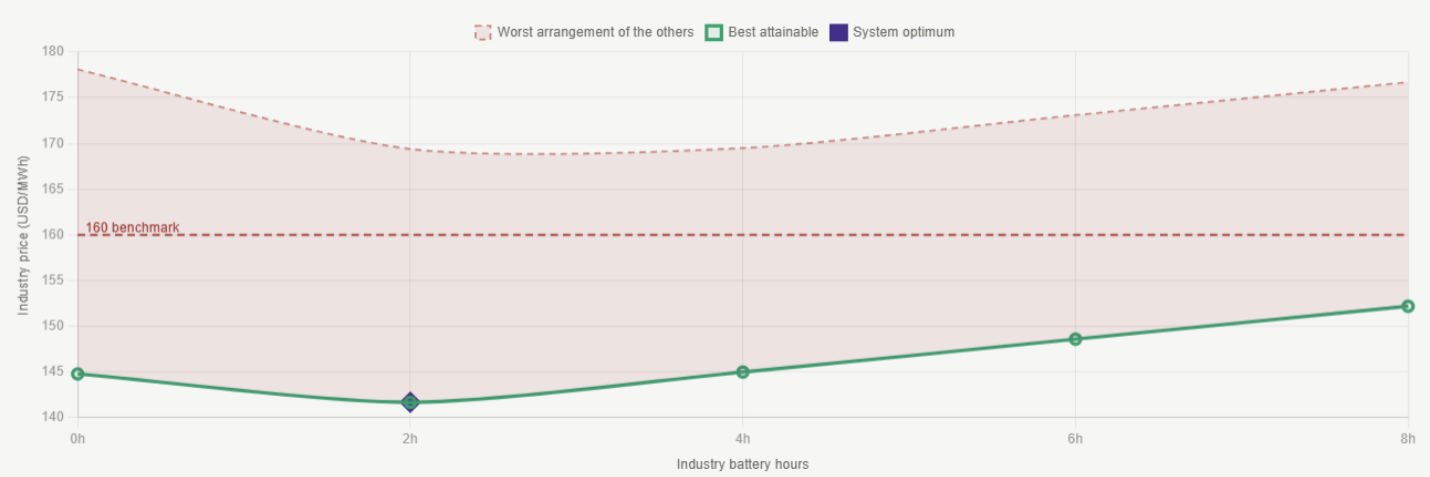


Exhibit 18. Industry Asset System Costs as a function of battery arrangements (illustrative)



The industry asset owner selects its battery size (and self-supply level) based on its own assumptions on other asset owners' choices on self-supply, battery and backfilling levels. High self-supply, 50% backfilling, 2030s costs. Green: the optimal configuration. Red shaded: other possible outcomes. System configuration: building centric, non-electric, central system service costs.

private optimum and social optimum potentially diverge, albeit by a small margin.

For 2030s costs, all asset owners select a high self-supply configuration, with different battery sizing. This configuration translates into a private optimum of $US96 per MWh, less than $US2 per MWh above the social optimum. Both private and social optimums converge.

In this configuration, differences in TSC thus remain limited, suggesting that private optimization may ultimately lead to the social optimum.

When considering a different pattern of selection, i.e., each asset owner assumes other assets' most favorable DERs arrangement, results remain robust for current US and 2030s cost. In the current world cost scenario, however, divergence may reach $US13–31 per MWh from the social optimum.

The results above also assume that each asset owner counts on 100% backfilling. When considering different assumptions on backfill levels, differences are significantly reduced, hence confirming the above conclusions (detailed tables are available in Appendix C).

Finding 9

The *social* optimum (minimum TSC attainable) is potentially distinct from the *private* optimum (rational choice for each asset owner). Both tend to converge, notably in the 2030s cost scenario. Incentives should focus on enabling change, more than dictating the DERs sizing at asset level.

Exhibit 19. Rational optimum for each asset type, assuming worst configuration from others

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	**210**	239	291	348	406
Med	277	280	321	376	434
High	347	346	377	413	459

Service

S/S	0h	2h	4h	6h	8h
Low	**180**	201	228	255	283
Med	192	194	220	247	275
High	228	218	219	233	260

Industry

S/S	0h	2h	4h	6h	8h
Low	**190**	200	218	236	254
Med	205	204	222	241	259
High	210	206	219	237	255

Private vs social

S/S	batteries	private	social	gap
Low **RSI**	0/0/0h	196.5	191.4	5.1
Med	0/0/2h	223.6	212.4	11.2
High	2/2/2h	248.7	248.0	0.7

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	**164**	176	210	250	291
Med	184	170	194	232	273
High	209	190	204	223	252

Service

S/S	0h	2h	4h	6h	8h
Low	155	167	186	205	224
Med	141	135	152	172	191
High	151	133	**126**	132	151

Industry

S/S	0h	2h	4h	6h	8h
Low	182	186	198	211	224
Med	188	182	195	207	220
High	185	**175**	182	195	208

Private vs social

S/S	batteries	private	social	gap
Low **R**	0/0/0h	167.9	155.4	12.5
Med	2/2/2h	145.1	145.1	0.0
High **SI**	2/4/2h	151.4	151.4	0.0

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	153	132	135	144	152
Med	161	116	107	114	123
High	174	124	106	93	**91**

Service

S/S	0h	2h	4h	6h	8h
Low	148	146	152	157	163
Med	127	107	111	117	122
High	131	99	78	**70**	75

Industry

S/S	0h	2h	4h	6h	8h
Low	179	174	178	182	185
Med	184	168	172	175	179
High	178	159	**157**	161	165

Private vs social

S/S	batteries	private	social	gap
Low	2/2/2h	129.5	129.5	0.0
Med	4/2/2h	106.4	106.4	0.0
High **RSI**	8/6/4h	95.5	93.9	1.6

Each asset's blended cost as a function of its own battery hours and self-supply choice, taking the worst arrangement of the other assets' batteries. 100% backfill is assumed. Green below 160, red above. System configuration: building centric, non-electric, central system service costs. At the bottom of each column, the resulting TSC from the selection (i.e., the private optimum).



Chapter V
Conclusion

Key findings

This research explores whether high DERs penetration leads to Total System Costs (TSC) of electricity that are higher, or lower, than today.

Through a detailed modeling integrating both distributed levelized costs and centralized infrastructure costs, we find that TSC are likely to become significantly more competitive in the near term, and that such consumer-led transition (with limited intervention) is likely to converge toward the social optimum (Exhibit 20).

Such reduction in TSC presents broader economic benefits. Additional income could reach 0.15–0.8% of GDP. The rapid rise in DERs is also a crucial opportunity to relocalize energy (in GDP terms), as 75% of the worldwide population lives in net-importing countries (Walter et al., 2025). It also contributes to creating jobs with estimates as high as 2 million jobs in the US and Europe alone (Sovacool et al., 2023). High DERs penetration thus offers opportunities for relocalization and expansion of economic activities at the local level, hence boost economic growth.

Policy implications: enabling change

The road to lower TSC under high DERs penetration requires however several policy provisions to ensure an effective transition. We suggest three key priorities below and propose a variety of instruments of economic, regulatory and informational natures (Rogge & Reichardt, 2016).

Priority 1: Flatten the load curve

A key benefit of DERs penetration is the generation of headroom on the centralized system. When deployed, DERs must thus work to reduce peak levels and flatten the load curve.

A primary tool is *economic* incentives. A previous study from the Schneider Electric Research Institute shows that DERs potential for energy and capacity headroom recovery varies greatly depending on the tariff incentives in place (Exhibit 21) (Minier & Utrilla Bustamante, 2026), e.g., the use of demand charges or time of use features.

Economic incentives should also support the combined deployment of PV and batteries, which require a specific (and often new) focus on battery deployment incentives (BloombergNEF, 2021).

Regulatory measures should complement these instruments with a focus on technology standards for controls and energy management at the asset level, including most recent AI technology development potential.

Finally, rating and labeling programs can prove to be an important *informational* instrument to foster convergence toward high DERs penetration and load flattening.

Exhibit 20. Summary of findings

Key findings from this report	
Finding 1	Under current world cost conditions, TSC are 10% below current levels. They further fall to -40% under 2030s cost conditions. In the US, however, they are for now 20% above current.
Finding 2	Optimal TSC do not vary by more than 17% when considering different load profiles and system mixes. Findings on TSC thus remain robust across system configurations.
Finding 3	Optimal choice of DERs penetration has a significant impact on TSC. While this has limited impact on conclusions in 2030s cost scenarios, it may raise TSC above the benchmark in current cost scenarios.
Finding 4	Residential is more exposed to higher costs when DERs costs are high. As costs go down, industry relative TSC decrease at a slower pace. Service buildings costs always score the lowest.
Finding 5	The optimization of TSC with high DERs penetration only works when coupled to parallel growth in electricity demand, i.e., electrification of the energy system.
Finding 6	The bulk of TSC optimization comes from substitution effects, while backfilling enables to limit the negative effect on grid utilization.
Finding 7	DERs without electrification and electrification without DERs both lead to inefficiency compared to the optimal TSC (although the effect is much lower when DERs precede demand). The transition to a high DERs power system may thus face temporary increases in TSC before they fall over time.
Finding 8	Regions differ in their dynamics of DERs deployment and electricity demand growth. They also differ in terms of the nature and state of their current centralized system. These will all affect the evolution of TSC in the short term.
Finding 9	The social optimum (minimum TSC attainable) is potentially distinct from the private optimum (rational choice for each asset owner). Both tend to converge, notably in the 2030s cost scenario. Incentives should focus on enabling change, more than dictating the DERs sizing at asset level.

Exhibit 21. Potential power headroom enabled by DERs systems under specific tariff structures

	Aus.	Can.	Chn.	Den.	Fra.	Ind.	Ita.	Nor.	Spa.	UK	US NE	US S	US W
Hospital	0,0	36,6	0,0	0,0	33,8	26,8	0,0	0,0	25,4	0,0	35,4	0,0	34,3
Large office	0,0	33,2	0,0	0,0	13,9	14,6	0,0	0,0	9,7	0,0	0,0	0,0	15,8
Secondary school	16,0	32,5	2,4	0,0	51,1	28,1	12,3	0,0	53,6	0,0	47,3	15,1	35,9
Small hotel	0,0	36,8	0,0	0,0	35,4	34,0	0,0	0,0	41,7	0,0	33,1	6,4	26,9
Strip mall	9,6	18,2	0,0	0,0	18,3	27,0	0,0	0,0	21,1	0,0	16,8	0,0	23,6

Power headroom measured in percentage of peak shaved. Detailed analysis of 5 service building archetypes across various geographies. The figure measures the percentage of peak reduction. Geographies differ in terms of weather impact, EV penetration levels, and more importantly retail tariffs. The microgrid algorithm here attempts to minimize total costs of operation for the dweller, without exceeding grid power limit.

Priority 2: Address the dynamics of change between supply and demand

To keep centralized costs (hence TSC) under control during the transition phase requires to manage both supply and demand together: DERs penetration must go alongside electrification of the energy system.

Economic instruments should focus on investment incentives. As long-term benefits are often discounted in conventional return on investment evaluations, access to better conditions can modify the way such investments are considered by both individuals and corporations.

Such *economic* incentives should also provision for combined DERs and electrification.

From a *regulatory* standpoint, building new should be about building right. Codes and standards on new build should incorporate both DERs and electrification.

Yet, it is the existing asset base that defines the pace of change (Atkeson & Kehoe, 1999). The electricity market design plays here a crucial role and often provides contradictory incentives: when electricity prices are high, they favor DERs deployment; when they are low, they favor electrification of uses. Yet, as our analysis shows, DERs costs are expected to fall further in the coming years. As a result, they will continue to contribute to reduced TSCs, suggesting the regulatory focus should be on lowering prices to incentivize electrification.

In many regions, system-level agents must also be incentivized through *regulatory* measures to focus beyond adequacy of supply, and include TSC, DERs penetration and demand side flexibility considerations in their investment plans.

Finally, there must be a focus on *informational* instruments such as public awareness campaigns to foster combined deployment.

Priority 3: Focus on supply chains development

Key to enabling the lowest TSC possible is the rapid reduction in unitary installed costs for DERs. Such reduction can only be enabled by the development of a vibrant and efficient supply chain.

From an *economic* perspective, policy must include access to affordable components, but also production incentives. Public procurement can also prove key to create the market that will initially support scaling and maturity of supply chains.

Regulatory instruments could focus on smarter deployment designs, involving codes and standards (at construction), and possibly embedded battery deployment in criti-

cal appliances. More importantly, the focus should be on streamlining red tape as "soft" costs of installation represent the bulk of DERs costs (Griffith, 2025).

Informational instruments should focus on upskilling and reskilling the workforce: there is today a widely recognized shortage of competent labor in the field. A focus on emerging AI technologies could also prove crucial.

Exhibit 22 summarizes our policy suggestions.

What was left unattended

This paper is a first-order analysis of TSC under high DERs penetration. It confirms that DERs can contribute to a significant reduction of TSC of electricity at global level, a promising avenue for increased energy resilience, and a platform for future GDP growth.

It also faces key limitations and raises some questions which represent future avenues for research.

Physical constraints

This work is primarily a cost evaluation model, based on a conceptual system, not a real physical one. Its focus is on the arithmetic of costs, rather than on actual physical limitations of the system, which in turn may be neglected.

First, standard annual load and solar profiles have been used, but results on TSC are likely to differ across geographies as these profiles vary. Our sensitivity analysis suggests impacts are real, but marginal, i.e., they do not change the conclusions of this paper. More applied research on specific networks will however be necessary to confirm these preliminary findings.

Second, the distribution of scenarios is not continuous: we assume pre-defined sets of PV and battery sizing, rather than continuous evolutions. This assumption implies that, at any given moment, the share of self-supply across a specific asset type is the same (e.g., all residential households exhibit the same self-supply level), which is obviously not the case in practice.

Third, although we account for system services and additional capital expenses for connection of new demand, this effort could be further enriched by more detailed analyses on actual, i.e., physical networks, revealing with more granularity the effects of high DERs penetration on grid operation and costs. Important topics not addressed in this paper may concern local congestion issues, the location of batteries (e.g., community batteries instead of individual provisions), the actual effect of high DERs penetration on system service costs, as well as potential capex deferrals.

Centralized generation

This paper has not delved into the implications of a high DERs system on centralized generation. Further analysis should be realized to understand the actual needs and constraints applying to the current centralized system. What will be the exact role of peaking plants and how much baseload generation will be required are all questions this paper does not address, let alone the long-term effects on the current capacities deployed.

Battery management and AI

For reasons of simplicity, this work has not delved into the many possible battery and load management strategies. We have focused on peak minimization and load flattening, at every hour of the day, every hour of the year. We have also assumed that no solar power was ever reinjected on the grid: it was either consumed, stored or curtailed, and the battery always charged on solar available. In practice however, different tariff incentives will lead to different system behaviors (e.g., net metering), as we studied in another research paper (Minier & Utrilla Bustamante, 2026). These naturally require further work. More complex management strategies than the one discussed here may also be unlocked with the concurrent rise of AI technologies.

DERs & electrification synchronization

The core argument developed in this research is the necessary coordination between DERs deployment and electrification. More work is needed to properly understand the dynamics of both, as they obey different incentives and follow different pathways.

Policy

The policy recommendations presented in the last section are a first attempt to sketch key principles of how to address the opportunity. More policy work and benchmarking are evidently required to address this complex multi-factor topic. Electricity market design, among other subjects, is a key priority. It must not only address future TSC but also tackle the distribution of costs across different asset types (e.g., subsidizing one type of consumer at the expense of another), a subject that this paper does not review.

Resources & trade

We have not discussed upstream implications of DERs deployment and electrification in terms of resource needs or trade implications. They will be crucial to review, although some work already exists (Energy Transitions Commission, 2025a).

Natural gas

The electrification of the economy will happen at the expense of gas networks which are hence more likely to face a death spiral (unlike electricity networks), an issue which will need to be properly handled. The implications and distributional effects of this transition across various parts of the population need to be further assessed.

Exhibit 22. Policy instruments for the transition

Instruments	Economic	Regulatory	Informational
Load curve	Dynamic tariffs (TOU, demand charges)	Technology standards	Rating & labeling programs
Supply vs demand	Combined investment incentives (e.g., PV + EV)	Codes & standards (mandates on new build) Electricity market design System level investment rules	Public awareness campaigns
Supply chains	Public procurement	Codes and standards Red tape streamlining	Workforce upskilling / reskilling

Financing

Finally, a crucial roadblock to DERs penetration is the financing of their deployment. The capital-intensive nature of DERs raises the question of how these provisions will be deployed across different asset types. This is a particularly acute question for the residential market. Conversely, how emerging financing and business models may affect future ASC, and whether these models will naturally lean toward the social optimum remain unanswered at this stage.

Looking at DERs in a new way

As a final reflection, we propose that the conventional thinking around solar, which classifies this resource as power generation, is misconceived. The real game-changer from high DERs penetration is electricity storage, i.e., batteries.

In a conventional system, natural gas is the fuel, and the gas turbine is the power generation asset. Following this analogy, we propose PV is the fuel, and batteries the generation asset.

This representation has not been widely adopted (nor understood) until now because batteries were not widely deployed, hence the argument against "intermittent" solar, which yields a negative cost impact on TSC when deployed alone (what our research confirms). Under this new analogy, however, solar becomes a formidable energy resource that can be harvested in large quantities everywhere, and batteries become the "dispatchable" mechanism which supplements conventional electricity systems.

> *What this analysis demonstrates is that distributed batteries represent a crucial avenue to harvest a new form of energy at highly competitive costs, leading to a new social optimum which can be source of future economic growth.*

Appendices

References, terminology, and technical appendices documenting the methodology (Appendix A), the transition scenarios (Appendix B) and the asset owners' rational choices (Appendix C).



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Terminology

Acronyms

AI	Artificial intelligence
ASC	Asset System Costs
Capex	Capital expenditure
DERs	Distributed energy resources (in this paper: rooftop PV and batteries)
EV	Electric vehicle
LCOE	Levelized cost of electricity
LCOS	Levelized cost of storage
PV	Photovoltaics (solar)
SLDC	System load duration curve
TOU	Time of use (tariff)
TSC	Total System Costs
VALCOE	Value-adjusted levelized cost of electricity (International Energy Agency)

Symbols

SS	Self-supply: solar production as a share of the asset's annual load (includes potential curtailment)
SC	Self-consumption: share of the asset's load met by solar
USC	Usable storage capacity at the asset level
Load	Annual load of the asset
VC	Variable centralized costs (generation and grid)
FC	Sunk fixed centralized costs (generation and grid)
K	Capacity multiplier: possible peak increase, as a multiple of the original peak (always above 1)
ER	Energy ratio: new energy delivered through the grid compared to the original
w	Weight of the asset: its share in aggregated annual energy demand

Key definitions

Total System Costs (TSC)	The entire expenditure on electricity for the economy: the sum of DERs costs and centralized (utility) system costs, expressed in $US per MWh.
Asset System Costs (ASC)	The cost point faced by each asset type (residential, service, industry), depending on the DERs deployed on site and the energy drawn from the grid. TSC are the weighted average of ASC.
Headroom	Capacity freed on the centralized system when DERs reduce peak demand.
Backfill	Additional electricity demand (electrification) filling the headroom created by DERs, up to the original peak.
Substitution effect	DERs substitute delivered generation through self-consumption.
Dilution effect	Changes in system utilization affect the dilution of fixed costs per MWh delivered.
Social optimum	The minimum TSC achievable at system level.
Private optimum	The configuration resulting from each asset owner selecting the most favorable arrangement for themselves, based on assumptions on others' choices.

Appendix A

Methodology

This appendix covers in greater detail the methodology chapter: definitions, formulas, and the full set of assumptions on load demand, DERs sizing, backfilling, DERs costs and centralized costs.

A.1 Definitions

DERs costs: these include the levelized cost of electricity (LCOE) of rooftop PV and the levelized cost of storage (LCOS) of batteries. DERs costs represent the combination of these installed costs times the energy produced and/or discharged (Eq. A1.1).

Centralized costs: these include both variable and fixed costs of the centralized utility grid:

- Variable generation and grid costs, which are a function of the energy flowing through the system.
- Fixed generation and grid costs, which are applied regardless of the amount of energy supplied by the system (Eq. A1.2).

A.2 Formulas

TSC are the sum of DERs costs and centralized costs.

Notation

Symbol	Meaning
LCOE	Levelized Cost of Electricity (PV). Capital recovery factor at 8% over 25 years plus operations and maintenance at 0.75% of capital cost per year.
LCOS	Levelized Cost of Storage (battery). Capital recovery factor at 8% over 20 years plus operations and maintenance at 1.5% of capital cost per year. Per design, the battery only charges from distributed solar production: there is no charging cost involved. Remaining solar production is not reinjected on the network and simply curtailed.
SS	Self-supply (SS) of an asset accounts for solar production as a share of the asset's annual load (it includes potential curtailment and should be distinguished from actual self-consumption).
SC	Self-consumption is the share of the asset's load met by solar.
USC	Usable Storage Capacity (USC) is the usable storage capacity at the asset level, a product of the battery size (hours of peak load), the depth of discharge, and the asset peak load.
Load	Annual load of the asset.
VC	Variable costs (VC) include both generation and grid costs.
FC	Sunk fixed costs (FC) account for the initial generation and grid costs.
K	Capacity multiplier (K) accounts for possible peak increases (in the context of demand increasing faster than the backfill potential): it is expressed as a multiple of the original peak and is always above 1.
ER	Energy ratio (ER) is the share of new energy delivered through the grid compared to the original.
Capex	Connection capex (Capex) is expressed as a function of MWh of backfill and is multiplied by the level of backfill.
System Services	System services account for additional centralized costs.
w	The weight of the asset (w) is its share in aggregated annual energy demand.

DERs costs

DERs costs follow Equation A1.1:

$$\text{DER}_{asset} = \text{LCOE}_{asset} \times \text{SS}_{asset} + \text{LCOS}_{asset} \times 365 \times \frac{\text{USC}_{asset}}{\text{Load}_{asset}} \quad \text{(Eq. A1.1)}$$

Centralized costs

Centralized costs follow Equation A1.2:

$$\text{Centralized Costs} = \text{VC} + \text{FC} \times \frac{K}{\text{ER}} + \text{Capex} \times \text{Backfill} \quad \text{(Eq. A1.2)}$$

Total System Costs

Total System Costs follow Equation A1.3:

$$\text{TSC} = \sum_{asset} w_{asset} \times \left(\text{DER}_{asset} + (1 - \text{SC}_{asset}) \times \text{Centralized Costs} + \text{System Services}\right) \quad \text{(Eq. A1.3)}$$

Once summed, the first term (DER_{asset}) accounts for the contribution of DERs to the total costs, and the second term to the resulting contribution of centralized (system) costs.

A.3 Assumptions

Load demand

We consider a conceptual system made of three types of assets, including residential and service buildings and industrial facilities.

Each asset type has its own load profile, with electricity demand varying across daytime hours and across seasons. Residential buildings exhibit a double peak shape across the day (morning and evening). Service buildings show an inverted U-shape, while industrial assets show flat demand across the day and lower demand at night (Exhibit A1). Demand for electricity rises in residential and service buildings in summer with air-conditioning.

Our original set of load profiles assumes heating is *non-electric*. We also develop an alternative set of profiles considering heating electrification of residential and service spaces. In this *all-electric* load configuration, residential energy increases by 69% and peak demand by 100%, while service energy and peak demand increase respectively by 34% and 38%.

The combination of these assets contributes to the system load duration curve (SLDC). In the *building centric* configuration, we assume 50% of the electricity is consumed by residential, 25% by service and 25% by industry, a profile close to western economies. In the *balanced* configuration, we assume 40% of the electricity consumed by residential, 20% by service and 40% by industry (closer to China's mix). These four configurations (non-electric vs all-electric × building centric vs balanced) represent the landscape of physical systems we explore in this report.

DERs sizing

We further size the deployment of rooftop PV on these assets. We define this sizing in terms of *self-supplied* electricity. We propose three sizing configurations: a low self-supply configuration, which assumes 30% self-supply for residential and service buildings, and 10% for industry; a medium self-supply configuration, which assumes respectively 60% and 20%; and a high self-supply configuration, which assumes 90% and 30% respectively.

We then define battery sizing in terms of peak-hours capacity. We set different sizes accordingly, assuming 0h – 2h – 4h – 6h and 8h of peak load hours.

The battery charging mechanism we program in this model is based on the logic to minimize costs for consumers while flattening the load curve. To this extent, it uses its available capacity to charge from excess PV and discharge to reduce peak levels and provide as flat a load profile as possible. Excess solar production is curtailed, i.e., there is no reinjection to the grid.

Backfilling

The combination of these load profiles yields an annual system load duration curve (SLDC) shown in Exhibit A2. This load duration curve is the basis of our system cost analysis. The area below the line represents the volume of energy supplied by the centralized system and flowing through the grid. It is thus an indicator of the centralized system utilization. In our baseline configuration, system utilization ranges between 58 and 66% across configurations (Exhibit A3 and Exhibit A2, black line).

As the peak is significantly reduced following the integration of DERs, the opportunity of putting more load on the grid emerges. In our simulation, we consider this headroom is "backfilled" with additional energy demand up to the original peak level (Exhibit A2, dashed orange line). The underlying hypothesis behind this backfill is a load factor of 0.85, assuming either relatively "flat" load demand additions (e.g., data centers, industry), or load demand additions inclusive of further DERs (i.e., with respective loads flattened). We consider three hypotheses for the extent to which backfill occurs: 0% backfill (no increase in electricity demand), 50% backfill (of the headroom), and 100% backfill (the original peak is restored).

DERs costs

DERs costs may vary significantly across space and time. We focus here on installed costs, not only the cost of equipment purchase (e.g., battery costs include provisions for the battery, as well as inverter, and electrical equipment and installation). We apply an 8% capital cost for the computation of LCOE and LCOS.

Exhibit A4 provides a summary of assumed installed costs of DERs technologies, based on the existing literature. 3 cases are considered: the current US case covers US installation costs; the current world case accounts for costs incurred in other geographies (it is an average considering significant dispersion across geographies); finally, the 2030s costs are a projection on how low these costs could get in the coming decade, assuming both a continued reduction in component costs and a significant decline in installed costs from learning effects and supply chain enablement.

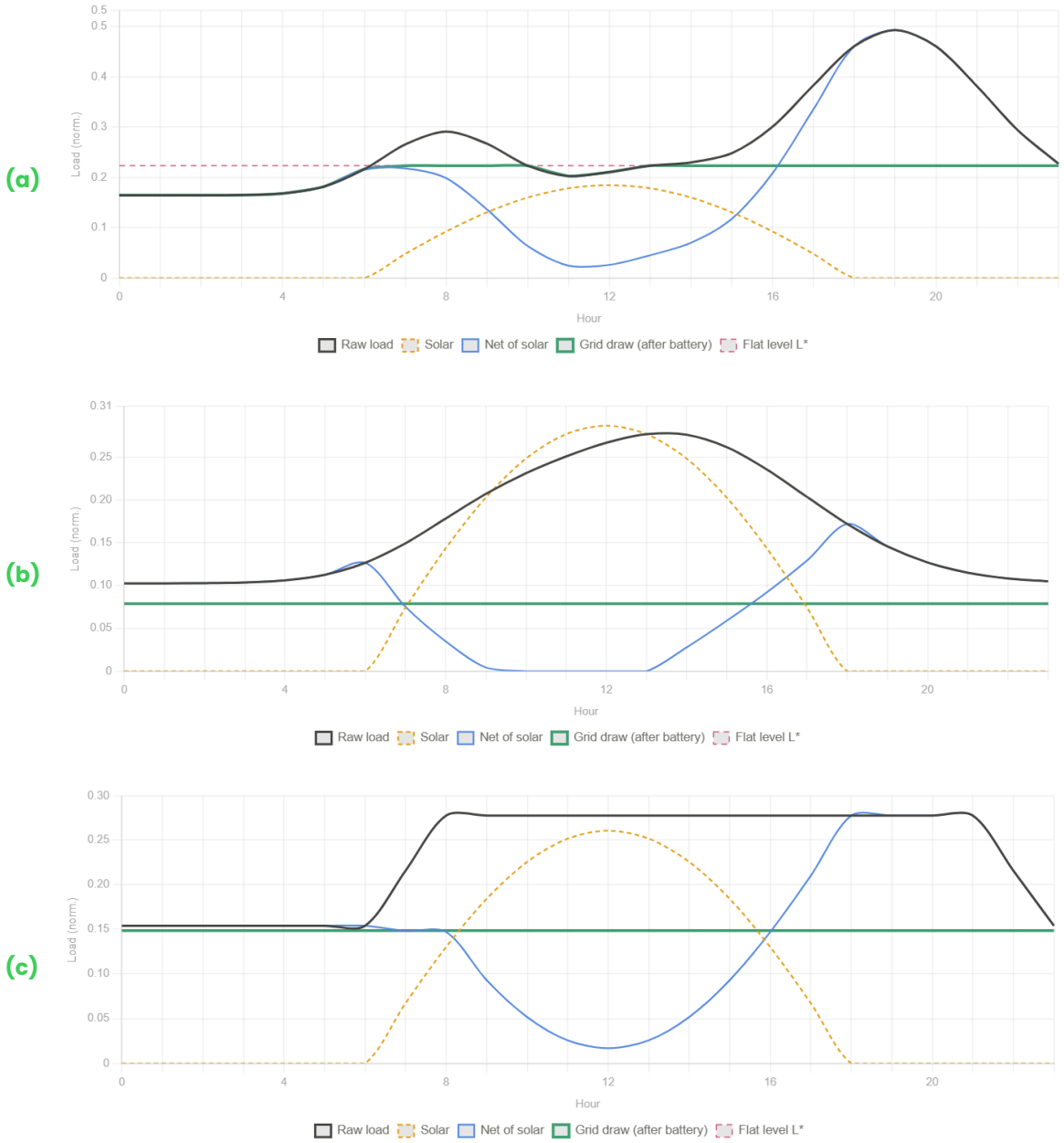
Centralized costs

In our conceptual system, we consider a centralized system with an overall cost of electricity of $US160 per MWh, excluding tax. This is roughly representative of the situation in most economies (Global Electricity, n.d.; OECD/IEA, 2026). It includes a generation component ($US90 per MWh, including 45% of fixed costs) and a grid component ($US70 per MWh, including 85% of fixed costs). Fixed costs thus account for around two-thirds of total.

As discussed, variable costs naturally vary with the volumes of electricity required from the centralized system.

The existing grid remains in place, hence fixed sunk costs remain stable. The penetration of DERs at asset level may however rise system service costs for reliability purposes. These include inertia, fast frequency response, ramping capability and voltage support. Various sources provide different estimates, depending on whether only the hardware required is considered (Brown et al., 2018), or the full set of marketed services in a typical network (Badesa et al.,

Exhibit A1. Illustrative examples of load profiles in the model



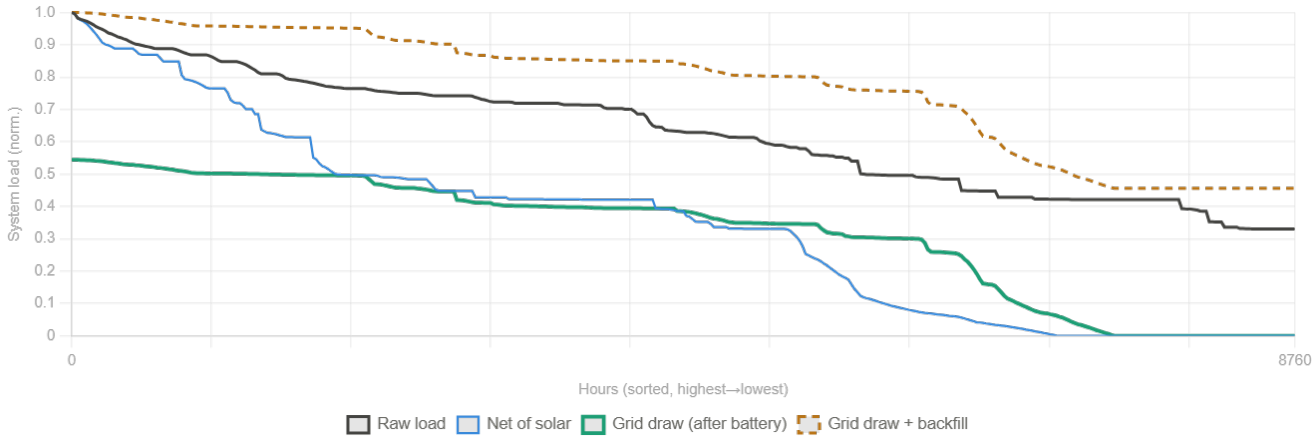
Dark line corresponds to the original load; yellow dashed line to the production of PV; blue line to the grid load following integration of PV; green line to the grid load after PV and batteries (a large battery size is selected here). (a) corresponds to a residential building, non-electric with low PV self-supply, on a winter day. (b) corresponds to a service building, non-electric with medium PV self-supply, on a summer day. (c) corresponds to an industrial building with medium PV self-supply, on a summer day.

2021), or a more islanded system (EirGrid, n.d.). Based on these sources, system service costs can range between $US1 and $US6 per MWh. However, they do not account for the provision of millions of batteries distributed across the system and very high penetration of DERs. Batteries themselves could in fact provide for system services, hence reduce system service costs, rather than increasing them. In light of such uncertainty, we consider here three possible outcomes: no penalty ($US0 per MWh), or a penalty of $US6 or $US12 per MWh.

Next, the backfilling of demand can lead to additional connection (capex) costs, but the level of these costs will depend on where the connection is made. We assume that 50% of increased demand will occur on sites where headroom has been created (e.g., electric vehicles or heat pumps in buildings, and partial electrification in industry), while the remaining 50% will occur on new sites (e.g., new data centers, new facilities). The former case does not require additional capex (at system level). For the latter, however, new connections need to be realized. We further assume that half of these new connections will materialize at transmission level and the other half at distribution level. We assume $US250 per kW for transmission (Lawrence Berkeley National Laboratory, 2026; RMI, 2023; Utility Dive, 2023) and $US700 per kW for distribution connections (Thunder Said Energy, 2026). These connection costs translate into minor annual cost increments of below $US6 per MWh (further weighted based on their share of overall electricity demand).

These assumptions are also conservative: they do not in-

Exhibit A2. Illustrative example of load duration curve in the model



Dark line corresponds to the original load; blue line to the grid load following integration of PV; green line to the grid load after PV and batteries (for a given select size of battery); dashed orange line to the grid load after all previous steps and backfilling. This illustrative example corresponds to a building centric configuration with non-electric assets, in a scenario with high PV self-supply and 2h of batteries on each asset type.

Exhibit A3. Central system utilization (baseline)

Configuration	System utilization baseline
Non-electric; building centric	62.7%
Non-electric; balanced	65.8%
All-electric; building centric	58.5%
All-electric; balanced	62.6%

Exhibit A4. DERs cost assumptions

DERs costs	Residential	Service & industry	Sources
PV ($/W)			
Current US	3	1.8	Feldman et al., 2024; HearthIQ, 2025; Lazard, 2025; Mirletz, 2024; Thomas, 2025
Current world	1	0.7	Boston University, 2025; HearthIQ, 2025; Solar Choice, 2026; Vatankhah Ghadim et al., 2025
2030s	0.5	0.4	Future projections on component and installation costs (BloombergNEF, 2025; Vatankhah Ghadim et al., 2025)
Batteries ($/kWh)			
Current US	1,000	500	Avepower, 2026; Cornett, 2026; Lazard, 2025; Mirletz, 2024
Current world	700	350	Haisic Energy Storage, 2026; Sunway Solar, 2026; Vatankhah Ghadim et al., 2025
2030s	150	100	Future projections on component and installation costs (BloombergNEF, 2025; Cole et al., 2025; Haisic Energy Storage, 2026; Polinovel, 2026; Vatankhah Ghadim et al., 2025)

tegrate any assumption for direct provisions of system services by DERs (i.e., from batteries) nor any assumption regarding potential capex deferral from electrification without DERs (i.e., the counterfactual is the original system). Recent evidence suggests minor benefits are possible (Rahdan et al., 2023).

Once backfill has occurred, the grid utilization is potentially improved, leading to a dilution of fixed costs (and notably existing sunk costs), yielding a decline of fixed costs in $US per MWh.

Appendix B

Timing between DERs and Electrification

This appendix provides the detailed numerical assumptions and results supporting the stepwise transition scenarios discussed in Chapter IV (DER-first, demand-first and coordinated).

Numerical results of transition costs

In the body of the paper, this section has highlighted numerical scenarios to show the stepwise approach toward reaching optimal TSCs. We provide below the detailed tables that support these scenarios (Exhibit B1).

Exhibit B1. Numerical results of transition costs

(a)

DER first — ends at 100.5

	2026	2030	2035	2040	2045	2050	end
Cost regime	—	World	2030s	2030s	2030s	2030s	2030s
Demand (energy)	0%	0%	0%	20%	40%	60%	90%
DER level	—	low	med	med	high	high	high
Battery r/s/i	—	0/0/0	2/2/0	2/2/0	6/6/0	6/6/0	6/6/2
Capacity ×	1.00	1.00	1.00	1.00	1.00	1.00	1.01
Utilization	63%	49%	39%	52%	49%	61%	79%
DER stock	0.0	15.6	28.5	28.5	46.5	46.5	47.9
Total system cost	**160.0**	**168.3**	**160.9**	**138.4**	**116.1**	**107.2**	**100.5**

(b)

Demand first — ends at 104.0

	2026	2030	2035	2040	2045	2050	end
Cost regime	—	World	2030s	2030s	2030s	2030s	2030s
Demand (energy)	0%	10%	30%	50%	70%	90%	90%
DER level	—	—	—	low	med	med	high
Battery r/s/i	—	—	—	0/0/0	2/2/0	2/2/0	8/6/0
Capacity ×	1.00	1.16	1.47	1.47	1.47	1.47	1.47
Utilization	63%	60%	55%	54%	56%	65%	53%
DER stock	0.0	0.0	0.0	8.2	21.1	21.1	43.1
Total system cost	**160.0**	**165.2**	**173.2**	**150.1**	**125.0**	**116.5**	**104.0**

(c)

Coordinated — ends at 103.9

	2026	2030	2035	2040	2045	2050	end
Cost regime	—	World	2030s	2030s	2030s	2030s	2030s
Demand (energy)	0%	10%	20%	40%	60%	80%	90%
DER level	—	low	low	med	high	high	high
Battery r/s/i	—	0/2/0	2/0/0	2/2/0	6/6/0	6/6/0	6/6/2
Capacity ×	1.00	1.02	1.02	1.02	1.02	1.02	1.02
Utilization	63%	53%	59%	63%	60%	72%	78%
DER stock	0.0	19.9	22.4	31.5	49.5	49.5	50.9
Total system cost	**160.0**	**163.2**	**155.7**	**129.1**	**111.1**	**105.0**	**103.9**

Each table shows the key assumptions for each step, i.e., the cost regime, the level of demand growth, of self-supply (DERs sizing and battery arrangement), the impact on peak versus the 1.0 benchmark (capacity), the resulting grid utilization and grid cost. (a) DER-first; (b) demand-first; (c) coordinated scenario.

Appendix C

Reaching the Optimum

This appendix provides the full detailed tables of rational asset owners' choices on DERs sizing, for all worst-case and best-case assumptions and backfill levels discussed in Chapter IV.

Asset owners' rational choices

We provide in this section a perspective on rational asset owners' choices on DERs sizing. We provide here full detailed tables for all cases discussed in the body of the paper.

Exhibit C1. Asset System Costs choices: worst case, backfill 100%

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	210	239	291	348	406
Med	277	280	321	376	434
High	347	346	377	413	459

Service

S/S	0h	2h	4h	6h	8h
Low	180	201	228	255	283
Med	192	194	220	247	275
High	228	218	219	233	260

Industry

S/S	0h	2h	4h	6h	8h
Low	190	200	218	236	254
Med	205	204	222	241	259
High	210	206	219	237	255

Private vs social

S/S	batteries	private	social	gap
Low RSI	0/0/0h	196.5	191.4	5.1
Med	0/0/2h	223.6	212.4	11.2
High	2/2/2h	248.7	248.0	0.7

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	164	176	210	250	291
Med	184	170	194	232	273
High	209	190	204	223	252

Service

S/S	0h	2h	4h	6h	8h
Low	155	167	186	205	224
Med	141	135	152	172	191
High	151	133	126	132	151

Industry

S/S	0h	2h	4h	6h	8h
Low	182	186	198	211	224
Med	188	182	195	207	220
High	185	175	182	195	208

Private vs social

S/S	batteries	private	social	gap
Low R	0/0/0h	167.9	155.4	12.5
Med	2/2/2h	145.1	145.1	0.0
High SI	2/4/2h	151.4	151.4	0.0

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	153	132	135	144	152
Med	161	116	107	114	123
High	174	124	106	93	91

Service

S/S	0h	2h	4h	6h	8h
Low	148	146	152	157	163
Med	127	107	111	117	122
High	131	99	78	70	75

Industry

S/S	0h	2h	4h	6h	8h
Low	179	174	178	182	185
Med	184	168	172	175	179
High	178	159	157	161	165

Private vs social

S/S	batteries	private	social	gap
Low	2/2/2h	129.5	129.5	0.0
Med	4/2/2h	106.4	106.4	0.0
High RSI	8/6/4h	95.5	93.9	1.6

Exhibit C2. Asset System Costs choices: worst case, backfill 50%

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	210	250	303	361	418
Med	277	290	332	388	446
High	347	358	387	420	464

Service

S/S	0h	2h	4h	6h	8h
Low	180	204	231	259	286
Med	192	198	225	252	280
High	228	222	222	235	262

Industry

S/S	0h	2h	4h	6h	8h
Low	190	204	222	240	258
Med	205	213	231	249	268
High	210	216	231	249	267

Private vs social

S/S	batteries	private	social	gap
Low RSI	0/0/0h	196.5	196.5	0.0
Med	0/0/0h	232.9	226.5	6.4
High	0/2/0h	266.4	262.6	3.8

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	164	187	223	263	303
Med	184	181	205	244	284
High	209	202	214	229	256

Service

S/S	0h	2h	4h	6h	8h
Low	155	170	189	209	228
Med	141	139	158	177	196
High	151	137	129	134	153

Industry

S/S	0h	2h	4h	6h	8h
Low	182	190	203	215	228
Med	188	191	203	216	229
High	185	185	194	207	220

Private vs social

S/S	batteries	private	social	gap
Low RI	0/0/0h	167.9	167.5	0.4
Med	2/2/0h	160.0	160.0	0.0
High S	2/4/0h	167.0	166.7	0.3

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	153	143	148	157	165
Med	161	126	118	126	135
High	174	136	116	100	95

Service

S/S	0h	2h	4h	6h	8h
Low	148	150	155	161	166
Med	127	112	116	122	127
High	131	103	81	73	78

Industry

S/S	0h	2h	4h	6h	8h
Low	179	178	182	186	189
Med	184	177	181	184	188
High	178	169	169	173	176

Private vs social

S/S	batteries	private	social	gap
Low	2/0/2h	145.1	143.6	1.5
Med	4/2/2h	122.3	122.3	0.0
High RSI	8/6/2h	108.4	108.1	0.3

Exhibit C3. Asset System Costs choices: worst case, backfill 0%

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	210	266	323	381	439
Med	279	309	355	416	473
High	359	387	416	442	480

Service

S/S	0h	2h	4h	6h	8h
Low	181	208	236	263	290
Med	204	214	242	270	297
High	262	252	242	250	277

Industry

S/S	0h	2h	4h	6h	8h
Low	191	209	227	245	264
Med	231	249	267	285	303
High	302	319	338	356	374

Private vs social

S/S	batteries	private	social	gap
Low RSI	0/0/0h	196.5	196.5	0.0
Med	0/0/0h	232.9	232.9	0.0
High	0/4/0h	279.5	273.2	6.3

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	164	202	243	283	323
Med	187	199	228	272	312
High	221	231	243	252	273

Service

S/S	0h	2h	4h	6h	8h
Low	155	175	194	213	232
Med	153	155	175	194	214
High	186	168	150	149	168

Industry

S/S	0h	2h	4h	6h	8h
Low	183	195	208	221	233
Med	214	227	239	252	265
High	276	288	301	314	327

Private vs social

S/S	batteries	private	social	gap
Low RI	0/0/0h	167.9	167.9	0.0
Med	0/0/0h	175.8	175.8	0.0
High S	0/6/0h	193.9	187.5	6.4

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	153	159	168	177	185
Med	164	144	141	154	162
High	186	165	145	122	111

Service

S/S	0h	2h	4h	6h	8h
Low	148	154	159	165	170
Med	139	127	134	139	145
High	165	133	102	87	92

Industry

S/S	0h	2h	4h	6h	8h
Low	180	184	188	191	195
Med	209	213	216	220	224
High	269	272	276	280	283

Private vs social

S/S	batteries	private	social	gap
Low I	0/0/0h	160.6	160.6	0.0
Med	4/2/0h	157.1	153.1	4.0
High RS	8/6/0h	159.0	153.7	5.3

Exhibit C4. Asset System Costs choices: best case, backfill 100%

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	197	232	287	344	402
Med	251	271	315	373	431
High	315	335	372	410	458

Service

S/S	0h	2h	4h	6h	8h
Low	145	171	199	226	254
Med	157	172	200	227	254
High	191	199	209	227	255

Industry

S/S	0h	2h	4h	6h	8h
Low	146	162	180	198	216
Med	148	163	181	199	217
High	151	164	182	200	218

Private vs social

S/S	batteries	private	social	gap
Low RSI	0/0/0h	196.5	191.4	5.1
Med	0/0/0h	232.9	212.4	20.5
High	0/0/0h	273.2	248.0	25.2

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	151	169	206	246	286
Med	158	161	188	229	269
High	177	180	199	220	251

Service

S/S	0h	2h	4h	6h	8h
Low	120	138	157	176	195
Med	107	113	132	152	171
High	115	114	116	126	145

Industry

S/S	0h	2h	4h	6h	8h
Low	137	148	161	173	186
Med	131	140	153	166	178
High	125	133	146	158	171

Private vs social

S/S	batteries	private	social	gap
Low R	0/0/0h	167.9	155.4	12.5
Med S	0/0/0h	175.8	145.1	30.7
High I	0/2/0h	171.4	151.4	20.0

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	140	126	131	140	148
Med	135	107	102	111	120
High	142	113	101	90	89

Service

S/S	0h	2h	4h	6h	8h
Low	113	117	123	128	133
Med	93	85	91	97	102
High	94	80	68	65	70

Industry

S/S	0h	2h	4h	6h	8h
Low	135	137	140	144	147
Med	127	126	130	134	137
High	118	117	120	124	128

Private vs social

S/S	batteries	private	social	gap
Low	2/0/0h	134.4	129.5	4.9
Med	4/2/2h	106.4	106.4	0.0
High RSI	8/6/2h	94.3	93.9	0.4

Exhibit C5. Asset System Costs choices: best case, backfill 50%

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	203	245	300	358	415
Med	262	283	327	386	443
High	330	349	382	417	463

Service

S/S	0h	2h	4h	6h	8h
Low	159	185	212	240	267
Med	171	184	212	239	266
High	205	209	215	231	258

Industry

S/S	0h	2h	4h	6h	8h
Low	163	179	197	216	234
Med	172	186	204	222	241
High	177	188	206	224	243

Private vs social

S/S	batteries	private	social	gap
Low RSI	0/0/0h	196.5	196.5	0.0
Med	0/0/0h	232.9	226.5	6.4
High	0/0/0h	273.2	262.6	10.6

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	157	182	220	260	300
Med	170	174	200	241	282
High	191	193	209	227	255

Service

S/S	0h	2h	4h	6h	8h
Low	133	151	170	190	209
Med	120	125	144	163	183
High	129	124	122	130	149

Industry

S/S	0h	2h	4h	6h	8h
Low	154	165	178	191	204
Med	155	164	176	189	202
High	152	158	170	183	195

Private vs social

S/S	batteries	private	social	gap
Low R	0/0/0h	167.9	167.5	0.4
Med S	0/0/0h	175.8	160.0	15.8
High I	0/4/0h	177.7	166.7	11.0

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	146	138	145	153	162
Med	147	119	114	123	132
High	157	127	111	97	94

Service

S/S	0h	2h	4h	6h	8h
Low	126	131	136	142	147
Med	107	97	103	108	114
High	108	90	74	68	74

Industry

S/S	0h	2h	4h	6h	8h
Low	152	154	158	161	165
Med	151	150	154	157	161
High	145	142	145	149	152

Private vs social

S/S	batteries	private	social	gap
Low	2/0/0h	146.5	143.6	2.9
Med	4/2/2h	122.3	122.3	0.0
High RSI	8/6/2h	108.4	108.1	0.3

Exhibit C6. Asset System Costs choices: best case, backfill 0%

Current US

Residential

S/S	0h	2h	4h	6h	8h
Low	210	266	323	381	439
Med	277	307	353	413	471
High	347	377	408	435	475

Service

S/S	0h	2h	4h	6h	8h
Low	180	207	235	262	290
Med	192	203	232	259	286
High	228	226	226	238	266

Industry

S/S	0h	2h	4h	6h	8h
Low	190	208	226	245	263
Med	205	224	242	260	278
High	210	228	246	264	282

Private vs social

S/S	batteries	private	social	gap
Low RSI	0/0/0h	196.5	196.5	0.0
Med	0/0/0h	232.9	232.9	0.0
High	0/4/0h	279.5	273.2	6.3

Current World

Residential

S/S	0h	2h	4h	6h	8h
Low	164	202	243	283	323
Med	184	197	226	269	309
High	209	221	235	245	268

Service

S/S	0h	2h	4h	6h	8h
Low	155	174	193	212	231
Med	141	144	164	184	203
High	151	142	133	138	156

Industry

S/S	0h	2h	4h	6h	8h
Low	182	194	207	220	232
Med	188	201	214	227	239
High	185	197	210	222	235

Private vs social

S/S	batteries	private	social	gap
Low RI	0/0/0h	167.9	167.9	0.0
Med	0/0/0h	175.8	175.8	0.0
High S	0/4/0h	190.0	187.5	2.5

2030s

Residential

S/S	0h	2h	4h	6h	8h
Low	153	159	168	177	185
Med	161	142	139	151	160
High	174	154	137	116	107

Service

S/S	0h	2h	4h	6h	8h
Low	148	153	159	164	170
Med	127	117	123	129	134
High	131	107	85	76	81

Industry

S/S	0h	2h	4h	6h	8h
Low	179	183	187	190	194
Med	184	187	191	195	198
High	178	181	185	188	192

Private vs social

S/S	batteries	private	social	gap
Low	0/0/0h	160.6	160.6	0.0
Med	4/2/0h	157.1	153.1	4.0
High RSI	8/6/0h	159.0	153.7	5.3

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