Powering the Future: Economic Considerations of Grid Expansion and Decentralized Solutions

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Introduction

Electric power systems globally face critical decisions regarding grid infrastructure, energy production, and mitigating risks associated with climate change. In addressing these and other concerns, agents in the energy sector are faced with an important question: *What are the economic trade-offs between centralized grid expansion and decentralized microgrids and battery storage deployment?* This study explores the conditions in which microgrids are economically and socially preferable to traditional grid expansion. This question is vital for policymakers aiming to implement cost-effective, sustainable electrification strategies.

Approximately 860 million people worldwide lacked electricity access as of 2019 [2], necessitating significant investment, around $51 billion annually, to achieve universal access by 2030, with decentralized microgrids anticipated to supply nearly 40% of new connections [2]. In developed regions, reliability concerns and climate change mitigation drive interest in microgrids, which provide local renewable-based resilience during outages, preventing costly interruptions [3]. However, centralized grids often offer economies of scale, delivering lower-cost electricity where infrastructure exists. Balancing these factors is essential for effective energy policy.

This analysis employs Cost-Benefit Analysis (CBA), a Computable General Equilibrium (CGE) model, and Agent-Based Modeling (ABM) to provide comprehensive insights. We anticipate that microgrids will be optimal in remote or underserved regions where grid extension costs surpass a certain distance threshold or reliability and environmental considerations dominate. Conversely, grid extensions will likely remain favorable in densely populated, network-accessible areas. This multi-method approach will clarify financial viability and broader welfare and adoption dynamics.

Literature Review

Existing research provides varied perspectives on decentralized versus centralized electrification. Cost-benefit analyses often identify a "break-even distance" at which microgrids become financially competitive. For example, a South African study determined that microgrids are economically preferable beyond approximately 130 km from existing grids, with closer distances favoring grid extension [7]. Costs of grid extensions commonly range from $20,000–$25,000 per kilometer in developing regions, influenced by terrain and local conditions [4]. Additionally, microgrids offer non-monetary benefits like enhanced reliability and reduced environmental impacts, factors frequently undervalued in traditional analyses. Models incorporating resilience highlight microgrids' advantage in protecting customers from costly blackouts [3].

Social and behavioral aspects also significantly influence adoption. Pasimeni (2019) demonstrated through agent-based simulations in Italy that local incentives, demand levels, renewable resource availability, and environmental attitudes strongly affect microgrid uptake, emphasizing targeted subsidies to accelerate adoption [6]. Despite economic viability, actual adoption depends substantially on behavioral responses and supportive policies. Our research builds upon these insights, integrating financial, economic, and behavioral analyses for a holistic assessment of decentralized energy viability.

Theoretical Framework

We utilize three distinct economic frameworks to evaluate electrification strategies comprehensively: Cost-Benefit Analysis, Computable General Equilibrium, and Agent-Based Modeling..

Cost-Benefit Analysis (CBA)

CBA assesses microgrid versus grid extension projects by calculating net present values (NPV), including capital, operating, and monetized benefit components over project lifespans. Utilizing social discount rates (5–10%) aligns our evaluation with typical energy infrastructure analyses [21]. A key assumption is that substantial non-market benefits, such as reliability improvements, are monetized where possible. Despite CBA's static nature and sensitivity to parameter assumptions, it provides essential baseline metrics like breakeven distances and comparative benefit-cost ratios to inform broader policy decisions.

Computable General Equilibrium (CGE) Model

Our CGE model evaluates economy-wide impacts by simulating electrification scenarios, capturing indirect effects across sectors. We model the economic implications of centralized versus decentralized investments in rural and urban settings using calibrated regional data from input-output sources such as GTAP and national accounts [5]. The CGE framework's strengths are in capturing systemic interactions like microgrid employment impacts and economic growth potential from improved energy access. While simplifications such as perfect competition and equilibrium assumptions limit dynamic realism, the CGE model provides valuable macroeconomic insights, illustrating impacts on GDP, employment, and overall welfare.

Agent-Based Modeling (ABM)

ABM simulates household-level adoption behaviors, accounting for heterogeneity and peer effects in microgrid uptake. Agents decide to adopt based on individual thresholds influenced by costs, perceived benefits, and neighbor behaviors. Incorporating social network dynamics and policy interventions, our ABM highlights real-world adoption processes and barriers like coordination issues and information deficits [6]. Although ABM outcomes are illustrative and dependent on behavioral assumptions, they reveal crucial qualitative insights, emphasizing the significance of targeted subsidies and pilot projects to stimulate adoption.

Data & Methodology

This study utilizes publicly available data for transparency and reproducibility. Key datasets include World Bank and IEA electrification figures, household load profiles from ESMAP and other surveys, grid extension costs from infrastructure case studies, microgrid component pricing from NREL and IRENA, and economic structure from GTAP. Data preprocessing steps involve merging datasets, calculating levelized costs of electricity, and initializing agent populations with realistic behavioral attributes. Each model component documents assumptions and data handling, ensuring clarity and facilitating robust policy conclusions.

CBA Implementation

Comparing the Net Present Value and Levelized Cost of Electricity for Grid Extension vs. Decentralized Microgrids

This section presents a cost-benefit analysis comparing centralized grid extension and decentralized microgrid deployment in rural U.S. settings. Using representative cost and performance data from the U.S. Department of Energy (DOE), National Renewable Energy Laboratory (NREL), and Energy Information Administration (EIA), the model estimates the relative economic viability of each approach over a 20-year project horizon. The analysis considers capital expenditures, operating costs, electricity demand, and avoided outage costs.

Table 1: Assumptions Table (CBA)

Variable	Value Used	Units
Q	100,000	kWh/year
V	$0.14	$/kWh
r	0.07	Discount rate
T	20	years
Cline	$25,000	$/km
d	Varied (50-150)	km
Cconnection	$50,000	Fixed
Cgen	$100/MWh	Levelized generation cost (central grid)
Co&m,grid	$20,000	Annual
Cpv	$1,300/kW	Capital cost
Cbattery	$400/kWh	Capital cost
Cinverter	$250/kW	Capital cost
Cinstall	$400,000	Lump sum
Co&m,mgrid	2% of capex	Annual
R	$100,000/year	Reliability value

Model Framework

The net present value (NPV) of each investment option is calculated as:

$$\mathrm{NPV}_i = \sum_{t=0}^{T} \frac{B_{i,t} - C_{i,t}}{(1+r)^t}$$

Where:

- $B_{i,t}$: Annual benefits, including electricity value and reliability
- $C_{i,t}$: Annualized capital and operating costs
- $r = 0.07$: Social discount rate
- $T = 20$: Project lifespan

We also compute the Levelized Cost of Electricity (LCOE) as:

$$\mathrm{LCOE}_i = \frac{\sum_{t=0}^{T} \frac{C_{i,t}}{(1+r)^t}}{\sum_{t=0}^{T} \frac{E_t}{(1+r)^t}}$$

where E_t is the energy delivered in year t.

The model is calibrated for a representative rural community of ~100 households with an aggregate electricity demand of 100,000 kWh/year.

Scenario A: Centralized Grid Extension

- Capital Costs:
  - Medium-voltage line construction: $25,000/km × 100 km = $2,500,000
  - Substation and connection infrastructure: $50,000
  - Total initial investment: $2,550,000
- Operating Costs:
  Annual O&M: $20,000
- Benefits:
  Value of electricity delivered: $0.14 × 100,000 = $14,000/year
  (Assumes no added value from resilience or outage avoidance)
- NPV Calculation:
  NPVgrid = PVbenefits−PVcosts = 153,010−(2,550,000+218,586) = −2,615,576
- LCOE:
  (2,550,000+218,586)/1,062,303 ≈ $2.60/kWh

Scenario B: Decentralized Microgrid

- Capital Costs:
  - 150 kW Solar PV: 150 × $1,300 = $195,000
  - 450 kWh Li-ion battery storage: 450 × $400 = $180,000
  - Inverter + system install: $400,000
  - Total investment: $775,000
- Operating Costs:
  2% of capital cost annually ≈ $15,500
- Benefits:
  Electricity value: $0.14 × 100,000 = $14,000
  Reliability benefit (avoided outages): $100,000/year

Total: $114,000/year

- NPV Calculation:
  NPVmicrogrid = 1,246,653−(775,000+169,960) = 301,693
- LCOE:
  (775,000+169,960)/1,062,303 ≈ $0.89/kWh

Break-Even Distance

Solving for the point where NPVgrid(d*)=NPVmicrogrid, we find:

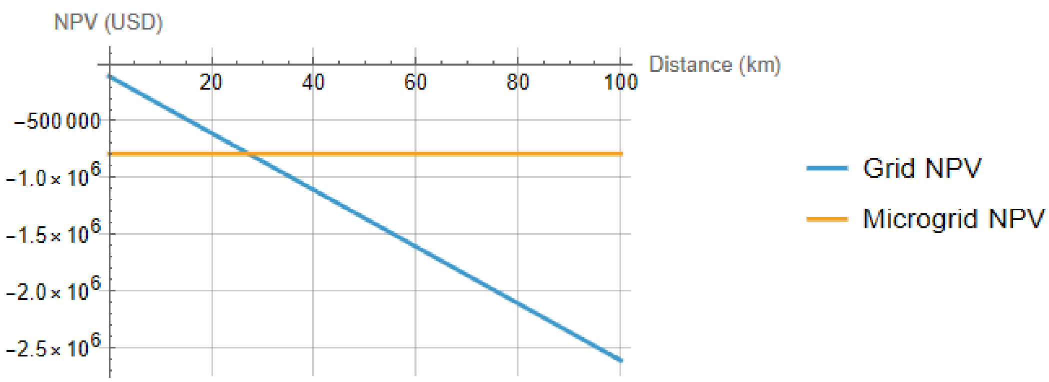
$$\sum_{t=0}^{T} \frac{B_t - [C_{\text{fixed}} + c_{\text{line}} \cdot d^* + C_{\text{O\&M}}]}{(1+r)^t} = \text{NPV}_{\text{microgrid}}$$

Factoring in reliability benefits for the grid, we can determine that

d*≈ 27.32 km

Grid extension becomes economically inefficient beyond this threshold, favoring microgrid and battery storage deployment.

Fig. 1 Break-even Distance



Interpretation

The results suggest that decentralized microgrids are significantly more viable in rural areas located more than 27 kilometers from the existing grid. While centralized systems benefit from scale, microgrids avoid high extension costs and deliver added resilience. Moreover, the LCOE for grid extension—over $2.60/kWh—is 3x higher than that of a well-sized microgrid when factoring in reliability value.

These findings support policy mechanisms like targeted grants and subsidies, cost-sharing programs, or performance-based incentives to support microgrid deployment in remote areas, particularly where grid expansion faces geographic or economic constraints.

CGE Implementation

Evaluating Macroeconomic Impacts of Centralized vs. Decentralized Energy Deployment in Rural and Urban Contexts

This section applies a simplified Computable General Equilibrium (CGE) model to evaluate how electrification strategies affect household utility and economic output in rural and urban settings. By comparing centralized grid expansion with decentralized microgrid deployment, the model reveals how regional characteristics, particularly capital intensity, labor share, and infrastructure access, shape the distributional and aggregate outcomes of energy policy.

Model Framework

We construct a two-sector economy in which a representative household consumes electricity (E) and other goods (X), and firms produce electricity using capital (K) and labor (L).

Utility Function:

$$U(E, X) = E^{\alpha} \cdot X^{1-\alpha}$$

Subject to a budget constraint:

$$P_E \cdot E + P_X \cdot X = I$$

Where:

- P_E: price of electricity
- P_X: price of other goods (normalized to 1)
- I: household income
- α: share of income spent on electricity

Production Function (Electricity):

$$E = A \cdot K^{\beta} \cdot L^{1-\beta}$$

Where:

- A: total factor productivity
- β: capital share in electricity production
- K, L: capital and labor inputs

This structure allows us to simulate changes in utility and GDP under two electrification strategies across rural and urban contexts.

Calibration and Assumptions

Key values are based on current U.S. data from BEA, BLS, and EIA:

Table 2: Assumptions Table (CGE)

Parameter	Urban	Rural
Household income ($)	60,000	40,000
Electricity price (P_E, $/kWh)	0.13	0.20
Electricity demand (kWh/year)	10,000	8,000
Alpha (electricity share)	0.05	0.12
Capital share in electricity (β)	0.65	0.45
TFP (A)	1.2 (grid)	0.85 (microgrid)

These parameters reflect the higher capital productivity and economies of scale in urban grid systems and the labor-intensive, locally managed rural microgrids.

Results

By solving for utility-maximizing consumption bundles and GDP using the calibrated functions, we are able to determine the impacts of each scenario. In urban areas, electricity is relatively cheap comparatively and results in a lower share of income spent on power. Through centralized grid expansion, it raises real utility by about 4.5%. Output growth would see an increase of about 2.1%, primarily due to capital investment and increased consumption.

In rural areas, microgrid and battery storage deployment would result in higher costs for users, with it representing a larger share of income allocated for power. Despite the higher costs, there is an increase in the perceived value due to avoided outages and reduced blackout risk. As a result, real utility for rural households increases by approximately 6.8%. There is a greater impact to the local economy as local labor engagement increases due to the installation and maintenance of the power systems, contributing to an approximate 2.6% increase to GDP.

Interpretation

This CGE simulation highlights a clear policy insight: rural electrification yields greater relative welfare gains from decentralized energy systems, despite their higher per-kWh costs. Rural communities benefit more from labor-intensive, locally owned infrastructure, which creates jobs and improves resilience without requiring grid extension.

Conversely, urban areas currently are better served by centralized systems, where high capital productivity and dense customer bases make centralized investment more efficient. Policymakers should avoid one-size-fits-all strategies. Instead, regionally differentiated subsidies, tax credits, and procurement standards can support efficient, equitable electrification.

ABM Implementation

Simulating Microgrid Adoption with Peer Effects and Policy Incentives

This section applies an agent-based model (ABM) to simulate household adoption of decentralized microgrid systems over time under two scenarios: a baseline with no intervention and a policy scenario in which households receive a 30% upfront cost subsidy. The model captures heterogeneous preferences, declining technology costs, and peer effects, key drivers of energy technology diffusion in real-world rural and urban settings.

Model Framework

We simulate a population of 100 agents, each representing a household with a unique threshold θi that reflects their willingness to adopt a microgrid system. This threshold is drawn from a uniform distribution on the interval [0,1], capturing variation in risk tolerance, capital constraints, and trust in new technologies.

At each time step t, a household adopts the technology if the perceived benefit B_i^t exceeds its threshold θi. Perceived benefit includes a deterministic cost-benefit term and a peer influence:

$$B_i^t = V_i - C_i^t + \phi \cdot \left(\frac{1}{|N_i|} \sum_{j \in N_i} A_j^{t-1} \right)$$

Where:

- V_i: perceived lifetime value of adopting a microgrid
- C_i^t: upfront cost at time t, declining over time
- $\phi = 0.1$: peer influence parameter
- N_i: peer group or social neighbors
- A_j^{t-1}: adoption state of neighbor j in the previous period

Peer effects increase perceived benefit as more households adopt, capturing social norms, demonstration effects, and information sharing.

Simulation Assumptions

Each household faces an initial system cost of $7,500, which declines by 5% annually due to learning effects and economies of scale. In the policy scenario, a 30% subsidy is applied beginning in year 0, effectively lowering the initial cost to $5,250. The simulation is run for 10 years, and adoption is evaluated annually. Once adopted, a household remains in the adopter state permanently.

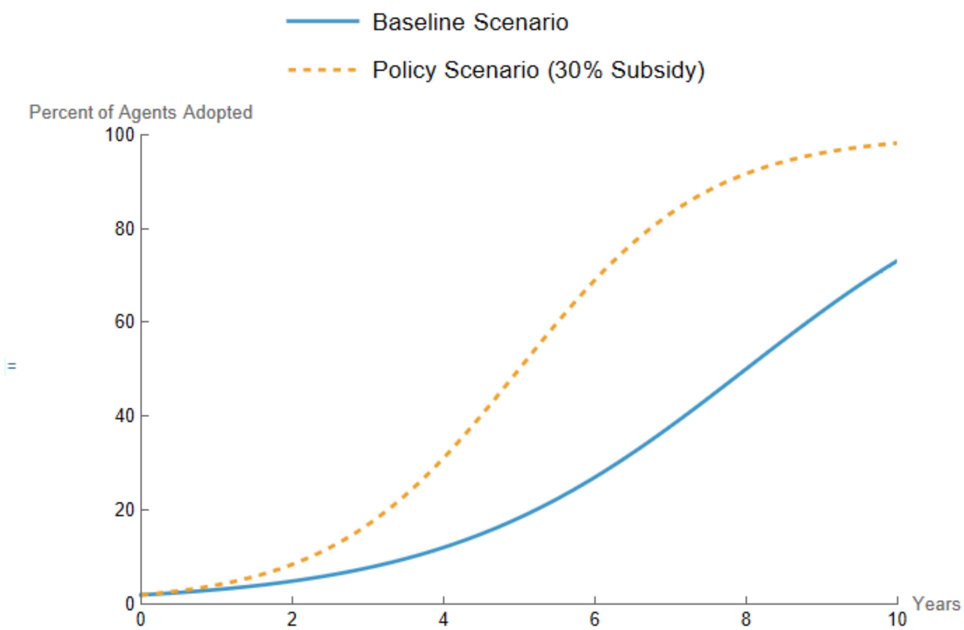
We assume that the perceived benefit V_i is drawn from a normal distribution with a mean of $6,500 and a standard deviation of $500, reflecting expectations of long-run savings and reliability improvements.

Results

In the baseline scenario, adoption begins slowly and remains under 15% for the first five years. As costs decline and peer effects accumulate, adoption accelerates, especially between years 6 and 9, and reaches approximately 68% of households by year 10. This reflects a classic S-curve pattern of diffusion, where early adopters drive social contagion and help overcome uncertainty for the majority (Fig. 1).

In the policy scenario, the initial subsidy significantly reduces the cost barrier, making adoption financially viable for more agents in earlier periods. Adoption begins earlier and rises more quickly, surpassing 40% by year 5 and reaching over 90% by year 10. The effect of the subsidy is nonlinear: by triggering earlier adoption, it strengthens peer effects and shifts the entire adoption curve forward.

Fig. 2: Microgrid Adoption Over Time



Interpretation

This simulation illustrates how both economic incentives and social dynamics affect the diffusion of decentralized energy systems. While peer effects alone eventually lead to widespread adoption, the process is slow and requires a critical mass of early adopters. Introducing a modest subsidy accelerates adoption not only through direct affordability but also by amplifying social influence. These findings suggest that well-timed public incentives can shift rural energy transitions from slow organic growth to rapid tipping points.

This model is particularly relevant in underserved rural areas where adoption risk is high and up-front capital costs are a primary barrier. By reducing early adopter costs, governments or NGOs can effectively "seed" adoption, improving the cost-efficiency of electrification programs and reinforcing behavioral norms that favor clean, decentralized infrastructure.

Conclusion

This study explored the economic tradeoffs between centralized grid extension and decentralized microgrid deployment, using a combined analytical approach of Cost-Benefit Analysis (CBA), Computable General Equilibrium (CGE) modeling, and Agent-Based Modeling (ABM). The analysis revealed that decentralized microgrids become economically advantageous in rural and underserved regions beyond approximately 27 kilometers from the existing grid. Specifically, microgrids demonstrated a positive net present value and a significantly lower levelized cost of electricity compared to grid extension when accounting for reliability and resilience benefits. Additionally, our CGE model indicated greater relative welfare improvements in rural areas, driven primarily by local employment effects and higher marginal utility from electricity access. The ABM further illustrated that modest upfront subsidies could substantially accelerate microgrid adoption by leveraging peer effects and overcoming initial adoption barriers.

These findings have critical implications for energy policy and managerial decisions regarding electrification strategies. Policymakers should consider geographically differentiated approaches, prioritizing decentralized microgrid investments in remote or rural areas where centralized grid extension becomes prohibitively costly. Targeted financial incentives and streamlined regulatory frameworks are also recommended to enhance social acceptance and accelerate decentralized energy adoption. However, our study has certain limitations, including the assumption of homogeneous agent behavior and perfect market conditions, which may oversimplify real-world scenarios. Future research should address these limitations by incorporating more detailed behavioral data, market frictions, and distributional impacts across diverse socio-economic groups. Additionally, longitudinal studies evaluating real-world microgrid implementations and their long-term socio-economic outcomes could provide valuable validation and refinement for the theoretical insights presented here.

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