

Response to the Editor and Reviewers

COTech 2026 – Stavanger, Norway

Manuscript: Integrated techno-economic assessment of PV–battery–micro gas turbine microgrids with thermal energy supply and storage pathways, grid support and electricity trading: a case study

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Dear Editor and Reviewers,

We thank the Editor and the two Reviewers for their careful reading of our manuscript and for their productive comments, which have helped us to improve the clarity, reproducibility and robustness of the paper. All comments have been addressed point by point below. In the revised manuscript, all new or modified text, equations, captions and table entries are shown in blue font. Unless stated otherwise, section, equation, figure, table and reference numbers in this response refer to the revised manuscript.

Comments of the Editor

Editor 1 – Reviewer/Editor comment

Only first letter of the title is abbreviated.

Authors' response

Thank you. The title has been converted to sentence case, with only the first word (and acronyms) capitalised, in line with the template.

Changes in the revised manuscript (blue text)

- Title: 'Integrated techno-economic assessment of PV–battery–micro gas turbine microgrids with thermal energy supply and storage pathways, grid support and electricity trading: a case study'.

Editor 2 – Reviewer/Editor comment

Name of authors must appear as follows: A.H S Weerakoon, M Assadi &and R Gholami*

Authors' response

The author line has been changed exactly as requested, using 'and' before the last author. Since all authors share one affiliation, the affiliation is given once below the author line and the corresponding author's e-mail address is marked with an asterisk, following the template.

Changes in the revised manuscript (blue text)

- Author line: 'A.H S Weerakoon*, M Assadi and R Gholami'; affiliation and corresponding e-mail reformatted using the template 'Authors', 'Addresses' and 'E-mail' styles.

Editor 3 – Reviewer/Editor comment

The manuscript requires thorough formatting. Format paragraph breaks, figure captions, table captions, tables, equations, ways of referring to captioned figures and list of references. You find the template with the correct format and information here:

<https://www.ux.uis.no/COTech/Template/COTechTemplate2023.docx>

Authors' response

We downloaded the COTech 2023 template and rebuilt the manuscript on it, so that all paragraph, caption, equation and reference styles of the template are used (11-pt Times, single spacing, justified text, A4 page set-up of the template). Specifically:

Paragraph breaks: the first paragraph after each heading uses the non-indented 'Bodytext' style and subsequent paragraphs the 5-mm indented 'BodytextIndented' style; sections, subsections and run-in subsubsections use the template's automatic numbering (e.g., '2.', '2.1.', '3.4.1.'). The abstract uses the

template ‘Abstract’ style and has been shortened to 189 words (limit: 200 words), without references or figure numbers.

Figure captions: all captions are placed below the figures as ‘Figure n.’ (FigureCaption style), end with a full stop and describe panels (a), (b), ... in one caption.

Table captions and tables: captions are placed above the tables as ‘Table n.’, and all 15 tables now have only three horizontal 0.5-pt rules (top, below the header and bottom) and no vertical rules, are centred and use reduced (9-pt) font size as permitted by the template.

Equations: all equations are centred with right-aligned numbers in parentheses, ‘(1)’–‘(29)’ (template EQN style), and are referred to in the text as ‘equation (n)’ instead of ‘Eq. 0n’.

Referring to figures and tables: ‘Fig. 0n’/‘Fig.n’ have been replaced by ‘Figure n’, and ‘Table 0n’ by ‘Table n’. During this revision we also corrected references to figure panels that did not exist in the original captions (Figure 5(f), 5(g), 7(e) and 8(d)) and other panel mismatches (Figure 8(b)/(c), Figure 7(d)).

List of references: the references now follow the Vancouver system, numbered in order of first citation, with consecutive citations compressed (e.g., [38–41]). All entries have been reformatted in the IOP style of the template (surname and initials, year, title, abbreviated journal title in italics, volume(issue), pages) with DOI. The bibliographic data of every reference were checked against its DOI record in Crossref, which also corrected some details (e.g., volume, issue and pages of ref. [3]).

Changes in the revised manuscript (blue text)

- Entire manuscript reformatted on the COTech template; tables restyled; equations renumbered (1)–(29); references renumbered and reformatted ([1]–[55]).
- Formatting-only changes (styles, rules, renumbering) are not coloured blue, to keep the changed content readable.

Comments of Reviewer #1

We thank Reviewer #1 for the positive assessment of the manuscript and for the detailed comments, which we have addressed as follows.

R1.1 – Reviewer/Editor comment

The scene has been well set for introducing the concept of microgrids, however there is a lack of literature review regarding techno-economic assessment of microgrids integrating renewables with thermal storage which is the core topic of this research.

Authors’ response

Thank the Reviewer for this comment. A focused literature-review paragraph has been added to the Introduction. It covers (i) reviews of the TEA of hybrid energy-storage systems with renewables [25] and of seasonal thermal energy storage [26]; (ii) microgrid-level TEA with multiple storage options and grid-connected community microgrids [27, 28]; (iii) CHP microgrids [29] and building-level PV–battery–heat-pump systems with thermal storage (TES) [30–32]; (iv) MGT-based and bio-fuelled gas-turbine microgrids [33, 34], including the closest study, which combines a biogas MGT with borehole thermal storage (BETS) and a heat-pump [35]; and (v) BTES at district level [36, 37].

Changes in the revised manuscript (blue text)

- Section 1, new paragraph starting ‘Techno-economic studies of renewable-based microgrids and multi-energy systems...’.
- 13 new references [25]–[37] added to the reference list.

R1.2 – Reviewer/Editor comment

The gap in literature research should be clearly identified in the introduction section and how authors are addressing this in their study.

Authors’ response

A new paragraph now states the research gaps explicitly: (1) most microgrid studies optimize electrical

subsystem and treat “heat” as a fixed demand or by-product, whereas thermal-storage/GSHP studies take grid electricity as given, so few studies compare a mixed-capacity MGT fleet, its recoverable heat & alternative thermal-supply technologies in one-hourly-framework; (2) the closest MGT–borehole–heat-pump study [35] focuses on borehole design for a single configuration without comparing heating pathways or grid price support; and (3) the effect of electricity-price support on the competitiveness of microgrid-based multi-energy supply in a cold climate has received less attention. The paragraph then lists how this study addresses these gaps: (i) one-hourly-framework linking PV, BESS, MGT dispatch, heat recovery and four thermal technologies; (ii) comparison of 08 scenarios against grid-only references with and without price support; and (iii) a sensitivity analysis of the key assumptions. The following objectives paragraph now begins with ‘To address these gaps, ...’.

Changes in the revised manuscript (blue text)

- Section 1, new paragraph starting ‘Despite this progress, three gaps remain...’ and revised opening of the final Introduction paragraph.

R1.3 – Reviewer/Editor comment

The manuscript includes many undefined abbreviations (PR, QHX, BG...etc). These need to be defined first time they are used. Otherwise, the authors can consider including a nomenclature or glossary in the article.

Authors’ response

Thank you. We have done both. A Nomenclature listing 44 abbreviations and 30 symbols, with units, has been added after the keywords. In addition, all abbreviations are now defined at their first use in the text, e.g. PV, BESS, TEA, MILP, NG, BG, Q_{HX} (rated recoverable thermal capacity), PR (performance ratio), DHW, DNI, CF, LCoE, LCoS, LCoH, RTE, PCS, BOS, EPC, HX, BHE, WHR and $EL_{heating}$. All new equation symbols are defined directly below the corresponding equations.

Changes in the revised manuscript (blue text)

- New ‘Nomenclature’ before Section 1.
- Definitions added at first use in Sections 1, 2.1–2.4, 3.1–3.5.

R1.4 – Reviewer/Editor comment

Methodology section is missing essential modelling equations. Many parts are hidden, this doesn’t allow validation of research work and reproduction of results. In section 2.2, the section below eq. 1 (dispatch logic) needs to be clarified in form of equations or flowchart diagram. Eq 1 only defines the operation of PV, also why considering that PV generation will be always lower than load as underlined by eq 1, there should be hours where PV generation exceed load demand during peak generation hours. Section 2.3, the modelling equation underlining the operation of electric heating boiler should be included. Section 2.4, all cost parameters included in eq. 3, 4 and 5 should be expressed by equations (NCF, CAPEX, Cby, Csy and Rsy,...etc). Nothing is clear about how those are calculated.

Authors’ response

We thank the Reviewer for this important comment. The methodology has been extended from **8 to 29 equations**, so that all reported quantities can be reproduced:

Section 2.2 (electrical dispatch): PV output model, equation (1); net demand, equation (2); PV surplus, equation (3); BESS energy balance and operating limits, equations (4)–(5); BESS sizing, equation (6); MGT power balance and unit-commitment limits, equations (7)–(8); MGT fuel input and recoverable heat, equations (9)–(10). We expressed the dispatch logic as equations together with an explicit rule rather than a flowchart, to save space: in each hour the heuristic commits the combination with the fewest units whose rated capacity covers the demand (ties resolved by the smallest combined capacity), sets committed units to a minimum load of 50% of rated power and allocates the remaining demand to the largest unit first. The pathway-dependent MGT demand (Pathways 1–3) is also defined.

PV generation exceeding the load: the Reviewer is correct that equation (2) clips negative values, and that the surplus was not described. Eq. (2) does not assume that PV generation is always lower than the load. The surplus is now defined by Eq. (3) and is first used for BESS charging, then exported or curtailed. In this

case study the midday demand falls to 16–21 kW (Fig. 2) while PV peaks at 17 kW, so surplus can occur only in a few midday hours and is small. We also clarify that the MGT pathway assessments dispatch the fleet against the gross demand (a conservative test of full electrical autonomy), while PV and BESS are evaluated separately in Sections 3.2–3.3.

Section 2.3 (thermal supply): models of the electric heater/boiler, equation (12), and of the NG/BG boilers, equation (13), have been added next to the GSHP model, equation (11).

Section 2.4 (economics): all cost terms are now given explicitly: electricity cost including spot price, grid tariff, taxes and price support, Eq. (16); fuel cost, Eq. (17); CO₂ cost, Eq. (18); fixed O&M cost, Eq. (19); trading revenue, Eq.(20); CAPEX and ΔCAPEX (in the text); annualised capital cost including replacement and salvage with the CRF, Eq. (21)–(22); daily cost including annualized CAPEX, Eq. (23); levelized costs, Eq. (24); and net cash flow NCF_{s,y}, Eq. (27). The definitions of $C_{b,y}$, $C_{s,y}$ & $R_{s,y}$ used in Eq. (26) are given explicitly. This also clarifies that the trading revenue is counted only once and that CAPEX enters the NPV only once (no double counting).

Reproducibility check: we verified that the methodology reproduce values reported in the paper. Examples: PV peak $25 \text{ kW} \times 0.8 \times 0.85 = 17 \text{ kW}$; BESS capacity $75/(0.85 \times 0.93 \times 0.95) = 99.87 \text{ kWh}$; BESS annualised CAPEX 4,097 €/year; Pathway-1 biogas use 17,429 MJ/day; NG-boiler emissions 1.84 tCO₂/day (165.8 €/day); and the unit-level MGT generation and operating hours in Tables 7, 9 and 11.

Changes in the revised manuscript (blue text)

- Section 2.2: new text and equations (1), (3)–(10), with definitions and the explicit dispatch rule.
- Section 2.3: new equations (12)–(13).
- Section 2.4: new equations (16)–(24) and (27), and clarification of $C_{b,y}$, $C_{s,y}$ and $R_{s,y}$.

R1.5 – Reviewer/Editor comment

Many of parameters listed in Table 3 are already stated in Table 2. No need for repetition, instead use this space to clarify the modelling equations in the methodology section.

Authors' response

All rows of Table 3 that repeated component-level data from Table 2 (PV capacity and PR, BESS capacity and round-trip efficiency, MGT sizes and efficiency range, heating efficiencies and COP) have been removed. Table 3 now contains only system-level assumptions (time step, electrical and thermal demand, peak thermal capacity, lifetime, discount rate, carbon price and trading revenue); the daily thermal demand (8119 kWh_{th}/day) was added because it is needed to reproduce the thermal results. The space saved is used for the new modelling equations (R1.4).

Changes in the revised manuscript (blue text)

- Table 3 shortened; Section 2.5 text states that Table 2 parameters are not repeated.

R1.6 – Reviewer/Editor comment

In Figure 2 caption, indicate that this a daily demand profile.

Authors' response

Corrected.

Changes in the revised manuscript (blue text)

- Figure 2 caption: ‘Daily (24-hour) commercial electrical and thermal energy demand profile of the case study at hourly resolution.’

R1.7 – Reviewer/Editor comment

In section 3.2, it is not clear how PV hourly generation is modelled and calculated? This should be explained in the methodology section. If a software has been used for this like PVsyst or others this should be indicated.

Authors' response

Thank you. Hourly PV generation is calculated with a performance-ratio model implemented in the authors’

TEA framework [19, 38], not with a commercial PV-design tool. The model is now given in Section 2.2, equation (1), $P_{PV,t} = P_{PV,r} \cdot (G_t/G_{STC}) \cdot PR$, with $P_{PV,r} = 25$ kW, $G_{STC} = 1000$ W/m² and $PR = 0.85$. With the irradiance profile of Figure 3(a), equation (1) gives the 17 kW peak and 102 kWh/day reported in Section 3.2, which is now referred back to equation (1).

Changes in the revised manuscript (blue text)

- Section 2.2, equation (1) and its description; Section 3.2 cross-reference to equation (1).

R1.8 – Reviewer/Editor comment

Daily costs indicated in results section, together with MGT electricity generation and thermal production are not supported by equations. The authors only included modelling equation for GSHP, modelling equations for MGT, heating boiler, BESS are missing.

Authors' response

This is addressed together with R1.4. The MGT models (unit commitment, fuel input and recoverable heat, Eq. (7)–(10)), the BESS models (Eq. (4)–(6)), the electric-heater and boiler models (Eq. (12)–(13)) and all daily cost components (Eq. (15)–(24)) are now included. Section 3.4 states that the pathway results are calculated with these equations, and the BESS, PV and thermal levelised costs in Sections 3.2–3.5 refer to Eq. (24).

Changes in the revised manuscript (blue text)

- Sections 2.2–2.4 (new equations); cross-references added in Sections 3.2, 3.3, 3.4 and 3.5.

R1.9 – Reviewer/Editor comment

In table 4 caption, the use of the term ‘sizing results’ here is not accurate. These are technical characteristics of selected BESS technology already stated in Table 2 and 3 under technical assumptions. Similarly, in Table 5 the term ‘results’ should be omitted, these are technical specs and cost parameters Not results.

Authors' response

We agree and have revised both captions and the corresponding sentence in Section 3.3.

Changes in the revised manuscript (blue text)

- Table 4: ‘Technical characteristics of the selected LFP BESS’.
- Table 5: ‘Techno-economic specifications and cost parameters of the selected LFP peak-shaving BESS’.
- Section 3.3: ‘Table 5 presents the economic boundary and cost parameters of the selected LFP BESS’.

R1.10 – Reviewer/Editor comment

The authors stated in the beginning that there will be 8 scenarios considered, however then regrouped those into 3 pathways and present obtained results for each pathway, however results are not well clarified for each of the 8 scenarios. Either to classify those from the beginning under 3 pathways and present corresponding results, or to subdivide into 8 scenarios and present results corresponding to each scenario. Mixing between both scenarios and pathways is confusing.

Authors' response

We thank the Reviewer for pointing out this misperception. We kept the 08 scenarios as the units of comparison and made the hierarchy explicit. The 03 MGT pathways (Section 3.4) and the 04 thermal-supply technologies (Section 3.5) are building blocks, and the 08 scenarios are combinations of them: S1–S2 are grid-only references; S3 corresponds to Pathway 2; S4–S7 combine Pathway 1 with electric heating, NG boiler, BG boiler and grid-supplied GSHP; and S8 corresponds to Pathway 3. Specifically: a new paragraph in Section 2.1 defines this hierarchy; a new **Table 14** gives, for each of the 08 scenarios, the electrical supply/pathway, the thermal supply, the daily and annualised cost and the differences relative to S1 and S2; Section 3.6 has been renamed ‘Comparison of the eight energy-supply scenarios’, and every scenario is labelled S1–S8 in the text; the Fig. 01 caption now states that the 05 numbered operating modes in the diagram are controller rules, not scenarios; and an error in **Table 1** has been corrected: S8 is the MG-

supplied GSHP scenario (it was listed as ‘Grid-supplied GSHP’).

Changes in the revised manuscript (blue text)

- Section 2.1 new paragraph; Table 1 (S8 row); Figure 1 caption; Section 3.4 linking sentence; Section 3.6 title, scenario labels and new Table 14.

R1.11 – Reviewer/Editor comment

Resolution of Figures 5, 6, 7 needs to be increased.

Authors’ response

Thank you. Figures 5–7 have been regenerated at **600 dpi** with larger, legible fonts and a consistent colour coding of the MGT unit sizes across the three figures. They are inserted at the full text width (16 cm). The regenerated figures are based on the hourly dispatch obtained with Eq. (7)–(10). This dispatch reproduces the unit-level generation and operating hours in Tables 7, 9 and 11, so the content of the figures is unchanged. Text references to non-existent panels (‘Figure 5(f)’, ‘5(g)’, ‘7(e)’) have been corrected.

Changes in the revised manuscript (blue text)

- Figures 5, 6 and 7 replaced (600 dpi); captions note the regeneration; panel references in Sections 3.4.1–3.4.3 corrected.

Comments of Reviewer #2

We thank Reviewer #2 for these two relevant methodological comments.

R2.1 – Reviewer/Editor comment

The annual techno-economic assessment appears to annualize results from a representative 24-hour simulation by multiplying daily costs by 365. This may not adequately capture seasonal variations in PV generation, electricity prices, electrical demand and especially heating demand. This could affect the economic comparison of the scenarios.

Authors’ response

We thank the Reviewer and agree that Eq. (25) annualizes the results of a representative day. We now state this clearly as a screening-level simplification. It follows from the aim of this conference paper, which is a consistent hourly comparison of the 08 supply scenarios under identical boundary conditions, rather than a full-year design optimisation. To keep the revision within the scope of the study, we have not replaced the representative day with a full-year simulation. Instead, we have assessed the likely effect on the scenario comparison as follows.

Thermal demand, the dominant seasonal driver, was varied by $\pm 20\%$ as a first-order seasonal proxy in the new sensitivity analysis (Section 3.7), together with $\pm 20\%$ variations of electricity and fuel prices. The lowest-cost scenario (S7) and the highest-cost scenario (S3) keep their ranks in all cases. The small margin of S8 over the subsidised grid (S1) does change sign, and we now report this transparently.

PV supplies about 102 kWh/day, i.e. about 7% of the daily electrical demand, so its seasonal variation has only a limited effect on the scenario comparison. Higher winter heating demand increases the absolute advantage of the efficient (GSHP-based) thermal pathways, because their cost advantage scales with the delivered heat.

A full-year (8760 h) simulation, or a representative-day approach with typical and extreme days [44, 45] based on Nordic seasonal price and demand data, is outside the scope of this conference paper. It will be reported in a subsequent study, as now stated in Section 4.

Changes in the revised manuscript (blue text)

- Section 2.4: new paragraph after equation (25) explaining the representative-day annualisation and its implications (new refs. [44, 45]).
- Section 3.7: thermal-demand and price variations.
- Section 4 (new), ‘Limitations of the study’, item ‘Temporal representation’; Section 6 (Conclusions), last-but-one paragraph.

R2.2 – Reviewer/Editor comment

A sensitivity analysis is needed for key economic assumptions, as the results depend strongly on prices, subsidies, COP, discount rate and CAPEX.

Authors' response

Authors have added a new Section 3.7, 'Sensitivity analysis of key assumptions', with **Table 15** and **Figure 12**. A one-at-a-time analysis was carried out for grid electricity price (which represents the effect of price support), biogas, NG and CO₂ prices ($\pm 20\%$ each), CAPEX ($\pm 20\%$), discount rate (3% and 7% instead of 5%), GSHP COP (3.0 and 4.0 instead of 3.5) and thermal demand ($\pm 20\%$). The scenario costs were distressed component-wise using the cost breakdowns already reported in Tables 6–13.

Main findings: S7 (MG + grid-supplied GSHP) remains the lowest-cost scenario (570–710 €/day) and S3 (full MG) the most expensive (1742–2490 €/day) in all 17 cases, so the main conclusions are robust.

The grid-only references are governed by the electricity price. The MGT-based scenarios S3, S6, S7 & S8 are most sensitive to the biogas price, because fuel accounts for 76–89% of the daily MGT cost.

The 42 €/day advantage of S8 (MG-supplied GSHP) over the subsidised grid (S1) is not robust. S8 becomes more expensive than S1 for a 20% lower grid electricity price (+171 €/day), a 20% higher biogas price (+124 €/day), COP = 3.0 (+44 €/day) or 20% lower thermal demand (+37 €/day). The 7 €/day difference between NG-boiler (S5) and BG-boiler (S6) also reverses with modest changes in fuel or CO₂ prices.

CAPEX and discount-rate variations change the daily costs by at most 3%, confirming that operating energy costs dominate the economics.

A probabilistic (Monte Carlo) risk analysis of parameter interactions is beyond the scope of the present paper and is listed in Section 4 as planned future work.

Changes in the revised manuscript (blue text)

- Section 3.7 (new), Table 15 (new) and Figure 12 (new); updated Section 2.5, abstract, Section 3.6 (S8 margin) and Conclusions.

Additional corrections made by the authors

- New Section 4, 'Limitations of the study', summarising the aspects outside the scope of this study: representative-day annualisation, deterministic one-at-a-time sensitivity, exclusion of GSHP ground-infrastructure costs, simplified representation of borehole thermal storage (BTES), reporting of daily/annualized costs rather than full NPV/PBP/ROI results, and simplified MGT/policy modelling. The former **Sections 4 (Future studies)** and **Section 5 (Conclusions)** are renumbered as Sections 5 and 6.
- Table 1: the S8 row has been corrected to 'MG-supplied GSHP / Tests heat-pump operation with MGT-supplied electricity', consistent with the results in Section 3.6.
- Section 3.3: the cross-reference for the 102 kWh/day PV generation has been corrected from Section 3.1 to Section 3.2.
- Figure 8: the text references now match the caption ((a) unit CAPEX, (b) daily fuel/electricity cost, (c) total daily cost).
- Section 2.4: we clarified that trading revenue enters the annual benefit **only-once** and that CAPEX enters the NPV only once, avoiding double counting.
- **Abstract and Conclusions:** updated to reflect the sensitivity analysis. The abstract has been shortened to the template limit.

We hope that the revised manuscript meets the expectations of the Editor and the Reviewers, and we thank them again for their valuable comments.

Authors

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Integrated techno-economic assessment of PV–battery–micro gas turbine microgrids with thermal energy supply and storage pathways, grid support and electricity trading: a case study

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Abstract. Rising electricity-price volatility, grid vulnerability and the need for secure, affordable and low-carbon energy supply are increasing interest in building-scale microgrids. This study presents an integrated techno-economic assessment framework for photovoltaic–battery energy storage–micro gas turbine (PV–BESS–MGT) microgrids with alternative thermal-supply pathways. Hourly dispatch modelling is linked with scenario-level economic analysis, including operating cost, capital cost, electricity-trading revenue, salvage value, payback period, return on investment and net present value. The framework is applied to a Norwegian case study in which eight energy-supply scenarios, combining PV generation, BESS peak shaving, MGT dispatch with heat recovery, electric heating, natural gas and biogas boilers and ground-source heat pumps (GSHP), are compared with grid-only references with and without electricity-price support. Microgrid feasibility is governed mainly by thermal integration rather than by electrical self-supply. The full MGT-based electricity and heat pathway gives the highest daily cost (2116 €/day), boiler-assisted microgrids approach the subsidised grid cost (1064 €/day) and the microgrid with grid-supplied GSHP gives the lowest cost (640 €/day). A one-at-a-time sensitivity analysis confirms this ranking, whereas the small advantage of the microgrid-supplied GSHP pathway over the subsidised grid depends on electricity and biogas prices.

Keywords: Techno-Economic-Assessment, Microgrid, Ground-Source-Heat-Pump, Thermal Alternatives, Electricity Trading.

Nomenclature

Abbreviations

ACC	annualised capital cost	LFP	lithium iron phosphate
BESS	battery energy storage system	MG	microgrid
BG	biogas	MGT	micro gas turbine
BHE	borehole heat exchanger	MILP	mixed-integer linear programming
BOS	balance of system	NCF	net cash flow
CAPEX	capital expenditure	NG	natural gas
CF	capacity factor	NPV	net present value
CHP	combined heat and power	O&M	operation and maintenance
COP	coefficient of performance	OPEX	operating expenditure
CRF	capital recovery factor	PBP	payback period
DA, DAM	day-ahead, day-ahead market	PCS	power conversion system
DHW	domestic hot water	PL	part load
DNI	direct normal irradiance	PR	performance ratio

DoD	depth of discharge	PV	photovoltaic
EL	electric(al)	ROI	return on investment
EPC	engineering, procurement and construction	RTE	round-trip efficiency
GSHP	ground-source heat pump	TE	techno-economic
HP	heat pump	TEA	techno-economic assessment
HX	heat exchanger	U _{hour}	unit-hour (one MGT unit operating for 1 h)
LCoE	levelised cost of electricity	WACC	weighted average cost of capital
LCoH	levelised cost of heat	WHR	waste-heat recovery
LCoS	levelised cost of storage	S1–S8	energy-supply scenarios (Table 1)

Symbols

$B_{s,y}$	annual benefit of scenario s in year y (€/year)	P_{el}, P_{th}	electrical and thermal demand (kW)
$C_{s,day}$	daily operating cost of scenario s (€/day)	$p_{DA,t}$	day-ahead electricity price (€/kWh)
$C_{s,day}^{tot}$	daily cost including annualised CAPEX (€/day)	p_{CO_2}	carbon price (€/tCO ₂)
C_{el}, C_{fuel}	electricity and fuel cost (€/day)	$Q_{th,t}$	thermal demand (kW _{th})
$C_{O\&M}, C_{CO_2}$	O&M and CO ₂ cost (€/day)	Q_{HX}	rated recoverable MGT heat (kW _{th})
$C_{fuel,k}$	fuel price (€/MJ)	Q_{rec}	recoverable MGT heat (kWh _{th})
E_t, E_{nom}	stored and nominal BESS energy (kWh)	R_{trade}	electricity-trading revenue (€/day)
$E_{HP,t}, E_{EH,t}$	GSHP and electric-heater electricity input (kWh)	r	discount rate (–)
EF_k	CO ₂ emission factor (kgCO ₂ /MJ)	S	salvage value (€)
$F_{i,t}$	fuel input (MJ)	$u_{i,t}$	unit on/off status (–)
G_t	solar irradiance (W/m ²)	Δt	time step (h)
N	project lifetime (years)	$\eta_{el}, \eta_{EH}, \eta_b$	MGT, electric-heater and boiler efficiency (–)
$P_{d,t}, P_{net,t}$	gross and net electrical demand (kW)	η_{RT}	BESS round-trip efficiency (–)
$P_{PV,t}, P_{sur,t}$	PV output and PV surplus (kW)	λ_{min}	minimum part-load ratio (–)
$P_{i,t}, P_{r,i}$	MGT unit output and rated power (kW)	σ_i, τ_i	price support, taxes and levies (€/kWh)

1. Introduction

Climate change, geopolitical fragmentation, and energy-market volatility are increasingly destabilizing the conventional balance between energy security, affordability, and sustainability [1]. The global climate system is already operating under intensified stress, with 2015–2025 identified as the hottest 11-year period on record [2] and the planetary energy imbalance reaching its highest level in the 65-year observational record [3]. These changes are no longer abstract long-term projections, they are now expressed through increasingly severe heatwaves, droughts, storms, floods, wildfires, and compound weather events that directly damage critical infrastructure and disrupt centralized energy networks [4]. This physical vulnerability is reflected in recent economic loss data, where natural disasters caused approximately USD 224 billion in global losses in 2025 [5], following USD 368 billion in inflation-adjusted losses in 2024 [6], with weather-related events accounting for more than 90% of 2025 losses [7]. At the same time, electricity systems are being forced to absorb rapidly increasing demand from electrified heating, transport, industry, air conditioning, and data centres [8]. Global electricity demand increased by 3.0% in 2025 after a 4.4% increase in 2024 and is projected to grow by approximately 3.6% per year during 2026–2030 [9], which is faster than the average growth rate of the previous decade. Therefore, the power system is being pushed from both sides, climate-induced infrastructure stress is increasing while electrification-driven demand is accelerating.

This pressure is further intensified by geopolitical tensions, sanctions, tariffs, trade restrictions, and the global restructuring of energy and technology supply chains [10]. Energy security is no longer limited to oil and gas availability; it now includes electricity reliability, cybersecurity, critical-mineral access, battery supply chains, photovoltaic (PV) manufacturing, power-electronics availability, and exposure to politically sensitive trade routes [11]. Current global clean-energy supply chains remain highly concentrated, with China accounting for around 85% of solar PV and 80% of lithium-ion battery supply-chain production capacity, including approximately 95% of PV wafer production and 97% of

anode-material production [12]. In parallel, export controls on critical minerals have expanded since 2023, including restrictions on materials such as gallium, germanium, and antimony, which are important for semiconductor and clean-energy technologies [13]. These developments show that the energy transition itself is becoming exposed to new forms of dependency and strategic competition, consequently the energy “trilemma” is becoming increasingly unbalanced [14]. Security is weakened by centralized-grid vulnerability and external supply-chain dependence [15]. Affordability is threatened by volatile electricity prices, grid tariffs, inflation, fuel-price uncertainty, and uncertain subsidy mechanisms [16]. Sustainability is constrained by the difficulty of replacing dispatchable fossil-based systems with reliable low-carbon alternatives at sufficient speed [17].

Within this context, microgrids are re-emerging as a highly relevant and practical energy-system architecture [16]. A microgrid can reduce exposure to centralized-grid failures and electricity-price volatility by combining local generation, storage, dispatchable backup, thermal integration, and demand-side flexibility within a controllable local boundary [17, 18]. Hybrid systems integrating PV, [battery energy storage systems \(BESS\)](#), Micro Gas Turbines (MGTs) [19], and thermal technologies such as electric heating, boilers, and ground-source heat pumps (GSHP) [20] can therefore provide not only economic optimization, but also resilience, energy autonomy, and operational flexibility [21, 22]. This is particularly important because real end-user energy cost is not determined by spot electricity price alone, but by the combined influence of grid import, grid rent, subsidies, fuel cost, CAPEX, OPEX, storage dispatch, thermal demand, financing assumptions & policy uncertainty [23, 24]. In this regard, a real-world techno-economic assessment of PV–MGT–BESS microgrids with alternative thermal-supply pathways provides a timely and practically relevant framework for evaluating future distributed energy systems.

Techno-economic studies of renewable-based microgrids and multi-energy systems have expanded rapidly, but they differ considerably in how the thermal side and thermal storage are represented. Reviews of the techno-economic assessment of hybrid energy-storage systems integrated with renewables [25] and of seasonal thermal energy storage [26] summarize the technical and economic performance of the main storage options; for seasonal storage, borehole and aquifer concepts show better economic performance, whereas only pit and low-temperature aquifer storage were found to be economically competitive with natural-gas and solar reference heating [26]. At the microgrid level, HOMER-based techno-economic assessments have been reported for hybrid renewable systems with multiple storage technologies [27] and for grid-connected community microgrids, where a PV–wind–diesel–battery configuration gave about 7% lower energy cost than grid-only supply and solar radiation, wind speed, interest rate and battery lifetime were the most sensitive parameters [28]. Combined heat and power (CHP) microgrids have been shown to supply the full electrical load and a large share (63.5%) of the thermal load of a remote community from renewable sources [29], while building-level studies have optimized PV–battery–heat-pump systems with thermal storage under uncertainty [30], PV-driven heat pumps with combined thermal and battery storage [31] and PV/thermal-assisted GSHP systems for multi-family houses in a heating-dominated climate [32]. Dispatchable MGTs have been integrated with renewables and hydrogen storage to improve microgrid economic returns, although at the expense of increased natural-gas consumption and emissions [33], and bio-fueled gas-turbine cogeneration has been combined with water-source heat pumps and gravity energy storage in a green microgrid [34]. Closest to the present work, a biogas-fueled MGT was coupled with seasonal borehole thermal storage and a heat pump, where excess MGT heat was charged into borehole heat exchangers and later extracted by the heat pump [35]. At district scale, Borehole Thermal Energy Storage (BTES) has been assessed for its environmental and economic performance [36] and in fifth-generation district heating and cooling, where borehole drilling was identified as a main contributor to the high upfront cost [37].

Despite this progress, three gaps remain. First, most microgrid TEA optimize the electrical subsystem and treat heat either as a fixed demand or as a by-product, whereas thermal-storage and GSHP studies typically take grid electricity as given; comparatively few studies compare, within one consistent hourly framework, the electrical role of a mixed-capacity MGT fleet, its recoverable heat and alternative thermal-supply technologies (electric heating, natural gas and biogas boilers, and GSHP). Second, the

MGT–borehole–heat-pump study closest to the present work [35] focused on the borehole design of a single configuration and did not compare competing heating pathways or the influence of grid electricity-price support. Third, the effect of electricity-price support schemes, such as those currently applied in Norway, on the competitiveness of microgrid-based multi-energy supply in a cold-climate context has received less attention. This study addresses these gaps by (i) linking hourly PV, BESS and MGT dispatch with MGT heat recovery and four thermal-supply technologies in one framework, (ii) comparing eight energy-supply scenarios with grid-only references with and without price support and (iii) testing the robustness of the scenario ranking through a sensitivity analysis of the key economic and technical assumptions.

To address these gaps, this paper presents an integrated **techno-economic assessment (TEA)** of hybrid PV–BESS–MGT microgrid pathways with alternative thermal-supply configurations for a Norwegian case study. The work links hourly electrical dispatch, MGT fuel use and heat-recovery potential, thermal supply by electric heating, natural gas boiler, biogas boiler, and GSHP, electricity trading revenue, and long-term discounted cash-flow indicators within one consistent framework. By comparing grid-only supply with and without price support against microgrid-assisted pathways, the study evaluates how dispatchable local generation, storage, fuel choice, thermal integration, and policy-sensitive electricity prices influence energy cost, investment performance, and future microgrid feasibility. As climate impacts, geopolitical uncertainty, and energy-affordability pressures intensify, microgrids are shifting from being optional local optimization assets to becoming fundamental infrastructure for secure, affordable, and net-zero-compatible energy planning.

2. Methodology

This study applies a TEA framework (already developed and published; Ref [19, 38–41]) to compare grid-only and MG-based commercial energy-supply pathways. The proposed methodology combines hourly electrical demand, PV generation, BESS, MGT dispatch, thermal-energy supply options, electricity-price support, and electricity export revenue (see Figure 1).

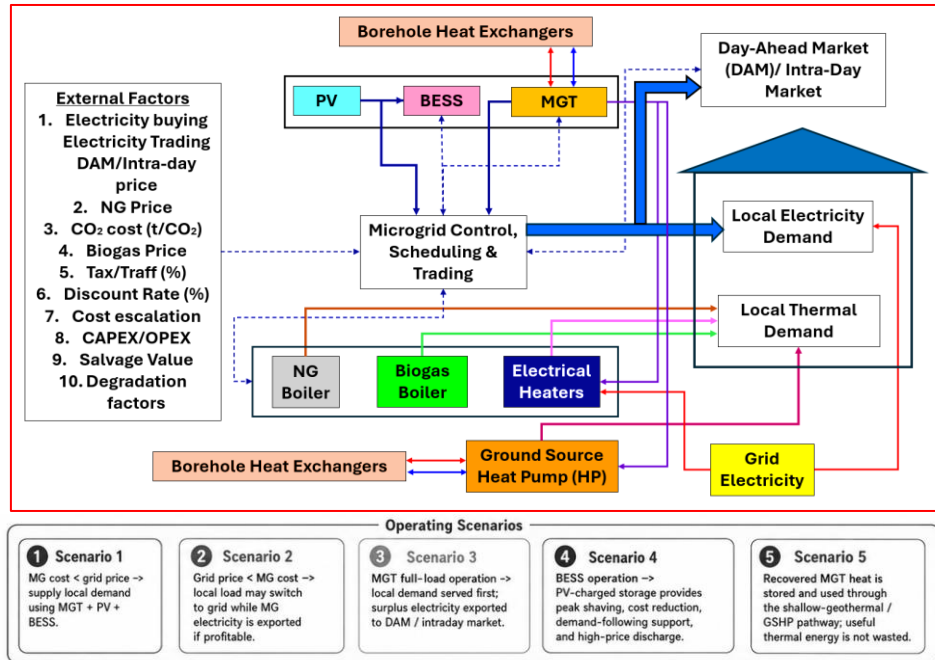


Figure 1. Microgrid energy-flow configuration (top) & smart-dispatch boundary conditions with market-integrated MG operation (bottom). The 05 numbered operating modes (lower diagram) are controller operating rules and are distinct from 08 energy-supply scenarios (S1–S8) defined in Table 1.

The detailed smart-control architecture, [mixed-integer linear programming \(MILP\)](#)-based scheduling, day-ahead market (DAM) participation, intra-day trading logic [38], and techno-economic (TE) scheduling strategy [19, 38] were developed and reported in the authors' previous works, see Refs. [19, 38–41]. Purpose of the methodology is to evaluate whether a commercial microgrid (MG) can reduce operating costs, improve energy flexibility, and support multi-energy coupling when compared with conventional grid-based supply. Assessment is carried out using hourly day-ahead electrical/thermal demand profiles. Electrical side of the system includes grid import, PV generation, BESS operation and dispatchable MGT generation. Thermal side includes electric heating, [natural gas \(NG\)](#) boiler, [biogas \(BG\)](#) boiler & GSHP. In selected MG cases, recoverable heat from MGT subsystem is additionally considered as a useful thermal-energy stream that can support the shallow geothermal/GSHP pathway.

2.1. System boundary and scenario definition

System boundary includes both electricity and heat demand of residential case-study. Grid-only cases used as reference pathways, while MG cases represent different levels of local generation, heating-system integration & exposure to electricity-market prices. [The analysis considers eight scenarios \(S1–S8\)](#), summarized in **Table 1**.

Table 1. Energy-supply scenarios considered in the study.

Scenario	Energy pathway	Electrical supply	Thermal supply	Main purpose of comparison
S1	Grid-only with subsidy	Grid	Electricity-based heating	Reference case with electricity-price support
S2	Grid-only without subsidy	Grid	Electricity-based heating	Reference case without electricity-price support
S3	Full microgrid pathway	PV + BESS + MGT	MGT-supported thermal pathway	Tests full local multi-energy supply
S4	MG + electric heating	PV + BESS + MGT	Electric heating/boiler	Compares direct electric heating with MG electricity
S5	MG + NG-boiler	PV + BESS + MGT	Natural gas boiler	Evaluates fuel-based thermal supply
S6	MG + BG-boiler	PV + BESS + MGT	Biogas boiler	Evaluates low-carbon fuel-based heating
S7	MG + GSHP (EL from Grid)	PV + BESS + MGT	Grid-supplied GSHP	Tests heat-pump operation under market electricity price
S8	MG + GSHP	PV + BESS + MGT	MG-supplied GSHP	Tests heat-pump operation with MGT-supplied electricity

This scenario structure allows the study to compare grid dependency, local self-supply, fuel-based heating, HP operation, electricity-price subsidy effects & microgrid-based energy flexibility within a consistent framework. The scenario pathways are constructed using a common set of MG and thermal-supply components. To maintain consistency across TE comparison, each component defines using rated capacity, main performance parameter, capital cost, fixed annual operating cost, energy or fuel-price assumptions. These assumptions form component-level input basis for the scenario-level cost calculation.

[To avoid ambiguity between scenarios and pathways, the following hierarchy is used throughout the paper. The eight scenarios \(S1–S8\) are the final energy-supply alternatives compared in Section 3.6. They are assembled from two sets of building blocks: \(i\) three MGT dispatch pathways \(Section 3.4\), which define how the MGT fleet is scheduled—Pathway 1 covers the electrical demand only, Pathway 2 additionally covers the electricity required for direct electric heating and Pathway 3 additionally covers the electricity required by the GSHP; and \(ii\) four thermal-supply technologies \(Section 3.5\), namely electric heating, NG boiler, BG boiler and GSHP. Accordingly, S1 and S2 are grid-only references, S3 corresponds to Pathway 2, S4–S7 combine Pathway 1 with the electric-heating, NG-boiler, BG-boiler](#)

and grid-supplied GSHP options, respectively, and S8 corresponds to Pathway 3. This mapping is given explicitly in Table 14 together with the results of each scenario.

Main TE assumptions used for MG & thermal-supply components are summarized in Table 2. CAPEX represents initial investment required for each technology, fixed OPEX represents annual cost associated with operation, inspection, service, routine maintenance. For MGTs, Table 2 also reports rated electrical output, electrical efficiency, recoverable thermal capacity (Q_{HX}), since these parameters directly affect fuel use, electricity generation & heat-recovery. This compact table provides the economic basis for scenario-level comparison, allows the contribution of each technology to be plainly identified [19, 22–24, 38–41].

Table 2. Component-level cost and performance inputs used for scenario construction.

Component / unit	Rated size or capacity	Main technical assumption	CAPEX	Fixed OPEX	Energy / fuel price assumption	Additional note
PV system	25 kW	PR = 0.85	€ 20,000	€1,000/year	—	OPEX assumed as 5% of CAPEX/year
BESS	25 kW / 99.87 kWh	DoD = 0.85; RTE = 0.93	€ 27,963.65	€419/year	0 €/kWh charging in base case	LFP battery; replacement be considered in later analysis
MGT unit	3 kW	$\eta_{el} = 0.15$; $Q_{HX} = 15 \text{ kWth}$	€ 20,000	€500/year	Scenario-dependent fuel price	Small-scale dispatchable unit
MGT unit	30 kW	$\eta_{el} = 0.26$; $Q_{HX} = 75 \text{ kWth}$	€ 60,000	€3,000/year	BG: 0.020 €/MJ in selected run	Used in MG dispatch
MGT unit	65 kW	$\eta_{el} = 0.29$; $Q_{HX} = 135 \text{ kWth}$	€ 110,000	€6,700/year	BG: 0.020 €/MJ in selected run	Medium MGT option
MGT unit	100 kW	$\eta_{el} = 0.30$; $Q_{HX} = 197 \text{ kWth}$	€ 160,000	€9,500/year	BG: 0.020 €/MJ in selected run	Main dispatchable MGT option
MGT unit	200 kW	$\eta_{el} = 0.33$; $Q_{HX} = 353 \text{ kWth}$	€ 265,000	€12,000/year	BG: 0.020 €/MJ in selected run	Large dispatchable MGT option
Electric heater	580 kWth	$\eta = 0.98$	€ 81,200	€1,218/year	0.030 €/MJ	Direct electric heating pathway
Natural gas boiler	580 kWth	$\eta = 0.89$	€ 98,600	€1,972/year	0.017 €/MJ	CO ₂ factor = 0.0561 kgCO ₂ /MJ
Biogas boiler	580 kWth	$\eta = 0.88$	€ 101,500	€2,030/year	0.022 €/MJ	Direct CO ₂ factor assumed as zero
GSHP	580 kWth	COP = 3.5	€ 159,500	€3,988/year	Scenario-dependent electricity price	Grid-supplied or MG-supplied HP operation

2.2. Electrical dispatch approach

Electrical dispatch evaluated at hourly resolution. PV generation is first used to reduce gross residential electricity demand. Remaining demand is then supplied by BESS, MGT units, or grid depending on the scenario and operating condition. Hourly PV output is calculated from the representative-day irradiance profile with a performance-ratio model implemented in the authors' TEA framework [19, 38], rather than with a dedicated PV-design tool such as PVsyst:

$$P_{PV,t} = P_{PV,r} \cdot \frac{G_t}{G_{STC}} \cdot PR \quad (1)$$

where $P_{PV,r} = 25 \text{ kW}$ is the rated PV capacity, G_t the hourly solar irradiance of the representative day (Figure 3(a)), $G_{STC} = 1000 \text{ W/m}^2$ the irradiance at standard test conditions and $PR = 0.85$ the performance ratio (PR), which lumps temperature, soiling, mismatch, cable and inverter losses. With the irradiance profile of Figure 3(a), equation (1) gives the 17 kW peak output and the 102 kWh/day reported in Section 3.2. Net demand after PV contribution is then calculated as [38]:

$$P_{\text{net},t} = \max(P_{d,t} - P_{\text{PV},t}, 0) \quad (2)$$

where $P_{\text{net},t}$ is net electrical demand after PV generation, $P_{d,t}$ is gross demand, and $P_{\text{PV},t}$ is PV power output at hour t . Equation (2) does not assume that PV generation is always lower than the load: in hours where the PV output exceeds the demand, $P_{\text{net},t} = 0$ and the PV surplus

$$P_{\text{sur},t} = \max(P_{\text{PV},t} - P_{d,t}, 0) \quad (3)$$

is first used to charge the BESS, and any remainder is exported, or curtailed when export is not economically attractive. In the present case study, the hourly electrical demand falls to 16–21 kW around midday (Figure 2) while the PV output peaks at 17 kW (Section 3.2), so a PV surplus can occur only in a few midday hours and is small. The BESS energy balance and operating limits are

$$E_{t+1} = E_t + \eta_{\text{ch}} P_{\text{ch},t} \Delta t - \frac{P_{\text{dis},t} \Delta t}{\eta_{\text{dis}}}, \quad \eta_{\text{ch}} = \eta_{\text{dis}} = \sqrt{\eta_{\text{RT}}} \quad (4)$$

$$(1 - \text{DoD}) E_{\text{nom}} \leq E_t \leq E_{\text{nom}}, \quad 0 \leq P_{\text{ch},t}, P_{\text{dis},t} \leq P_{\text{PCS}} \quad (5)$$

where E_t is the stored energy, $P_{\text{ch},t}$ and $P_{\text{dis},t}$ the charging and discharging power, η_{ch} and η_{dis} the one-way efficiencies derived from the round-trip efficiency η_{RT} , DoD the depth of discharge and P_{PCS} the rating of the power conversion system (PCS). The BESS is charged from daytime PV generation and discharged during peak-demand or high-price hours. Its nominal capacity follows from the peak-shaving requirement:

$$E_{\text{nom}} = \frac{P_{\text{ps}} t_{\text{dis}}}{\text{DoD} \cdot \eta_{\text{RT}} \cdot k_{\text{T}}} \quad (6)$$

where P_{ps} is the peak-shaving power, t_{dis} the discharge duration and k_{T} the temperature de-rating factor (Section 3.3).

MGT fleet is treated as the dispatchable generation source of MG. Dispatch logic selects available MGT units to meet remaining electrical demand while avoiding excessive oversupply. BESS is used as a flexible support unit, mainly for peak shaving, PV energy shifting, reducing grid import during high-price periods. When electricity export is economically attractive, surplus MGT electricity is considered a potential revenue stream instead being curtailed. In each hour, the committed MGT units must satisfy

$$\sum_i u_{i,t} P_{i,t} = P_{\text{MGT},t}^{\text{dem}} + P_{\text{os},t}, \quad P_{\text{os},t} \geq 0 \quad (7)$$

$$u_{i,t} \lambda_{\text{min},i} P_{r,i} \leq P_{i,t} \leq u_{i,t} P_{r,i}, \quad u_{i,t} \in \{0,1\} \quad (8)$$

where $P_{i,t}$ is the output of unit i , $P_{r,i}$ its rated power, $u_{i,t}$ its on/off status, $\lambda_{\text{min},i}$ its minimum stable part-load ratio and $P_{\text{os},t}$ the oversupply. The pathway-dependent demand $P_{\text{MGT},t}^{\text{dem}}$ equals $P_{d,t}$ in Pathway 1, $P_{d,t} + Q_{\text{th},t}$ in Pathway 2 (thermal demand transferred one-to-one to the electrical load for direct electric heating) and $P_{d,t} + E_{\text{HP},t}/\Delta t$ in Pathway 3 (Section 3.4). In the MGT pathway assessments, the fleet is dispatched against the gross demand $P_{d,t}$, i.e. a conservative condition without PV and BESS support, so that the ability of the fleet to provide full electrical autonomy is tested; the PV and BESS contributions are evaluated separately in Sections 3.2 and 3.3. In each hour, the dispatch heuristic [38] commits the combination with the fewest units whose combined rated capacity covers the demand (ties are resolved by the smallest combined capacity); committed units are first set to their minimum load $\lambda_{\text{min},i} P_{r,i}$, with $\lambda_{\text{min},i} = 0.5$, and the remaining demand is allocated to the largest committed unit first. The minimum-load constraint explains the small oversupply in the low-load hours 1–6 of Figure 5(a), where the 30 kW unit cannot operate below 15 kW. Unit fuel input and recoverable heat are calculated as

$$F_{i,t} = \frac{3.6 P_{i,t} \Delta t}{\eta_{\text{el},i}} \quad (9)$$

$$Q_{\text{rec},i,t} = \frac{Q_{\text{HX},i}}{P_{r,i}} P_{i,t} \Delta t \quad (10)$$

where $F_{i,t}$ is the fuel input (MJ), $\eta_{el,i}$ the electrical efficiency of unit i , 3.6 MJ/kWh the energy-conversion factor and $Q_{HX,i}$ the rated recoverable thermal capacity of unit i (Table 2). Fleet totals are obtained by summation over all units and hours. With the rated efficiencies and capacities of Table 2, equations (7)–(10) reproduce the unit-level generation, operating hours, fuel use and recoverable heat reported in Tables 6–11 (e.g., 17,429 MJ/day of biogas and 2927.6 kWh_{th}/day of recoverable heat in Pathway 1).

2.3. Thermal-energy supply approach

Thermal demand is evaluated by using alternative heating pathways. Electric heating/boiler-based systems are modelled using heating efficiency, while GSHP modelled using Coefficient of Performance (COP) [42, 43]. For GSHP pathway, the required electrical input is estimated as [42]:

$$E_{HP,t} = \frac{Q_{th,t}\Delta t}{COP} \quad (11)$$

Where $E_{HP,t}$ is GSHP electricity input, $Q_{th,t}$; hourly useful thermal demand, Δt is hourly timestep, COP is HP coefficient of performance [43]. **Direct electric heating and fuel-fired boilers are modelled with constant heating efficiencies:**

$$E_{EH,t} = \frac{Q_{th,t}\Delta t}{\eta_{EH}} \quad (12)$$

$$F_{b,t} = \frac{3.6Q_{th,t}\Delta t}{\eta_b}, \quad b \in \{NG, BG\} \quad (13)$$

where $E_{EH,t}$ is the electricity input to the electric heater/boiler (kWh), η_{EH} its efficiency, $F_{b,t}$ the fuel input to boiler b (MJ) and η_b the boiler efficiency (Table 2). The corresponding energy costs and CO₂ emissions follow from equations (16) – (18).

In full MG/MG–GSHP cases, thermal pathway is linked with electrical dispatch through recoverable heat from MGTs. This recovered heat can support shallow-geothermal/GSHP pathway & improve overall energy utilization. Therefore, MG is assessed as a coupled electricity–heat system.

2.4. Techno-economic assessment

The TE comparison is based on daily operating cost, initial investment, fuel cost, electricity cost, carbon cost, trading revenue & long-term discounted cash flow. Daily operating costs are first calculated for each scenario; then converted into annual values. Investment cost is treated separately as initial CAPEX to avoid double counting. Main economic indicator used for scenario comparison is net present value (NPV); calculated as [39]:

$$NPV_s = -\Delta CAPEX_s + \sum_{y=1}^N \frac{NCF_{s,y}}{(1+r)^y} \quad (14)$$

Where NPV_s is the net present value of scenario s , $\Delta CAPEX_s$ is incremental capital investment, $NCF_{s,y}$ is net cash flow in year y , N is the project lifetime, and r is the discount rate (%).

In addition to NPV, several supporting indicators are calculated to interpret economic behavior of each pathway. Daily operating cost of each scenario is first estimated by combining electricity cost, fuel cost, fixed operating cost, carbon cost, while deducting any electricity-trading revenue [24, 38, 39]:

$$C_{s,day} = C_{el,s} + C_{fuel,s} + C_{O\&M,s} + C_{CO_2,s} - R_{trade,s} \quad (15)$$

Where $C_{s,day}$ is total daily operating cost of scenario s , $C_{el,s}$ is electricity cost, $C_{fuel,s}$ is fuel cost, $C_{O\&M,s}$ is operation and maintenance cost, $C_{CO_2,s}$ is carbon cost, and $R_{trade,s}$ is electricity-trading revenue.

The cost components in equation (15) are calculated from the hourly dispatch results as

$$C_{el,s} = \sum_t E_{grid,t} (p_{DA,t} + p_{grid,t} + \tau_t - \sigma_t) \quad (16)$$

$$C_{fuel,s} = \sum_t \sum_k F_{k,t} c_{fuel,k} \quad (17)$$

$$C_{CO_2,s} = \frac{p_{CO_2}}{1000} \sum_t \sum_k F_{k,t} EF_k \quad (18)$$

$$C_{O\&M,s} = \frac{\sum_k OPEX_{fix,k}}{365} \quad (19)$$

$$R_{trade,s} = \sum_t E_{exp,t} p_{DA,t} \quad (20)$$

where $E_{grid,t}$ is the grid import, $p_{DA,t}$ the day-ahead spot price, $p_{grid,t}$ the grid tariff (grid rent), τ_t taxes and levies, σ_t the electricity-price support (zero in the non-subsidised case), $F_{k,t}$ the fuel input to component k from equations (9) and (13), $c_{fuel,k}$ the fuel price (€/MJ), EF_k the direct CO₂ emission factor (kgCO₂/MJ), p_{CO_2} the carbon price (€/tCO₂), $OPEX_{fix,k}$ the fixed annual O&M cost of component k and $E_{exp,t}$ the exported electricity. Capital costs are calculated as $CAPEX_k = c_k X_k$, where c_k is the specific cost and X_k the installed capacity, and $\Delta CAPEX_s = \sum_k CAPEX_{k,s} - CAPEX_b$. For the component-level comparison (Sections 3.2–3.5) and the daily scenario costs (Section 3.6), CAPEX is converted into an equivalent daily charge using the annualised capital cost (ACC)

$$ACC_k = [CAPEX_k + \sum_j CAPEX_{rep,k,j} (1+r)^{-y_j} - S_k (1+r)^{-N}] \cdot CRF \quad (21)$$

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1} \quad (22)$$

$$C_{s,day}^{tot} = C_{s,day} + \frac{\sum_k ACC_k}{365} \quad (23)$$

where $CAPEX_{rep,k,j}$ is the j -th replacement cost in year y_j , S_k the salvage value and CRF the capital recovery factor. For the BESS (replacement in year 12, salvage value 7.5% of CAPEX, $r = 5\%$ and $N = 15$ years), equation (21) gives the annualised CAPEX of 4,097 €/year listed in Table 5. Levelised costs of electricity (LCoE), storage (LCoS) and heat (LCoH) are obtained by dividing the daily component cost by the corresponding delivered daily energy:

$$LCo_X = \frac{C_{X,day}^{tot}}{E_{X,day}}, \quad X \in \{PV, BESS, th\} \quad (24)$$

In the NPV of equation (14), CAPEX enters only once as the upfront $\Delta CAPEX_s$, and the ACC term of equation (23) is not included, which avoids double counting of the investment cost.

Daily cost is then converted to an annual operating cost as [24]:

$$C_{s,annual} = 365 C_{s,day} \quad (25)$$

Equation (25) annualises the representative-day results. This is a screening-level simplification that does not capture the seasonal variation of PV output, electricity prices, electrical demand and, in particular, heating demand in Stavanger; representative-day selection methods with several typical and extreme days are known to reduce this annualisation error [44, 45]. Its influence on the scenario comparison is examined in Section 3.7 through variations of thermal demand and energy prices, and is further discussed in Section 4.

Annual economic benefit of each MG pathway is calculated relative to the selected reference case [19]:

$$B_{s,y} = C_{b,y} - C_{s,y} + R_{s,y} \quad (26)$$

Where $B_{s,y}$ is annual benefit of scenario s in year y , $C_{b,y}$ is annual cost of baseline case, $C_{s,y}$ is annual cost of evaluated scenario, $R_{s,y}$ being annual electricity-trading revenue. To avoid double counting of trading revenue, $C_{s,y}$ in equation (26) is the annual operating cost before trading revenue, $C_{s,y} = 365(C_{el,s} + C_{fuel,s} + C_{O\&M,s} + C_{CO_2,s})$, $C_{b,y}$ is the corresponding annual cost of the baseline and $R_{s,y} = 365 R_{trade,s}$. The net cash flow in equation (14) is then

$$NCF_{s,y} = B_{s,y} - C_{rep,s,y} + S_s \delta_{y,N} \quad (27)$$

where $C_{rep,s,y}$ is the replacement cost incurred in year y , S_s the salvage value and $\delta_{y,N}$ equals 1 in the final year and 0 otherwise.

Simple payback period (PBP) estimated as [39]:

$$PBP_s = \frac{\Delta CAPEX_s}{\bar{B}_s} \quad (28)$$

Where PBP_s is simple payback period, $\Delta CAPEX_s$ is additional investment cost relative to baseline, and $\bar{B}_s$ is average annual benefit.

Return on investment (ROI) calculated as [24]:

$$ROI_s = \frac{\sum_{y=1}^N B_{s,y} - \Delta CAPEX_s}{\Delta CAPEX_s} \times 100 \quad (29)$$

Where ROI_s expresses total return over the project lifetime relative to initial investment. These indicators are used together with NPV to compare daily cost, payback behaviour, profitability and long-term economic attractiveness of each energy pathway.

2.5. Main assumptions

Main technical/economic assumptions used in analysis are summarized in Table 3; **component-level parameters already listed in Table 2 are not repeated**. These values define the base-case model and are varied in the sensitivity analysis of Section 3.7 [19, 21–24, 38–43].

Table 3. Main technical and economic assumptions used in the assessment.

Category	Parameter	Base value used	Unit / note
Time resolution	Timestep	1.0	hour
Electrical demand	Daily electrical demand	1387.21	kWh/day
Thermal demand	Peak thermal capacity	580	kWth
Thermal demand	Daily thermal demand	8119	kWhth/day
Project lifetime	Economic period	15	years
Discount rate	WACC / discount rate	5.0	%
Carbon price	CO ₂ price	90	€/tCO ₂
Trading revenue	Scenario-dependent revenue	120–220	€/day

3. Results and Discussion

3.1. Load Profile

Case study considers a commercial/residential load demand profile in Stavanger (see Figure 2). Electrical load (kW) & thermal load (**domestic hot water (DHW)**, heating/cooling) (kW) are considered at each hour.

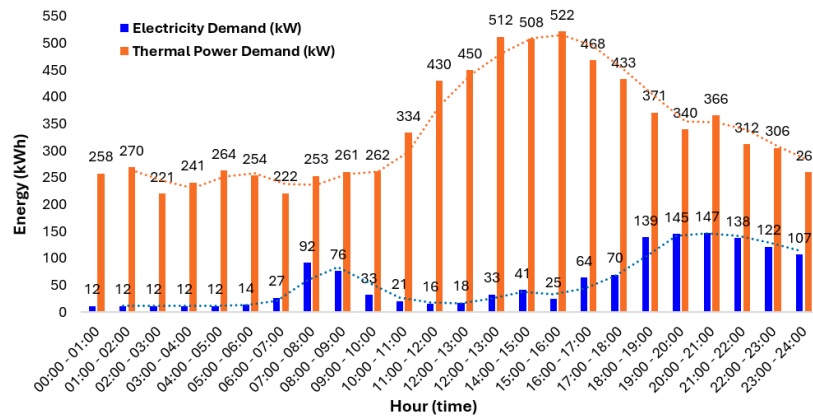


Figure 2. Daily (24-hour) commercial electrical and thermal energy demand profile of the case study at hourly resolution.

3.2. PV-Power Generation

First stage evaluates electricity generated by PV subsystem using a representative 24-hour **direct normal irradiance (DNI)** profile and **equation (1)**. PV system modelled with rated capacity of 25 kW, an overall performance ratio of 0.85, a CAPEX of 20,000 EUR, operational period 15 years. Generated PV electricity intended to support MG directly and to charge BESS for later peak-shaving operation during high-cost electricity periods. Figure 3(a) shows hourly DNI profile and corresponding PV power generation. Solar availability occurs between 9h and 19h, with maximum DNI~ 800 W/m² at 14h.

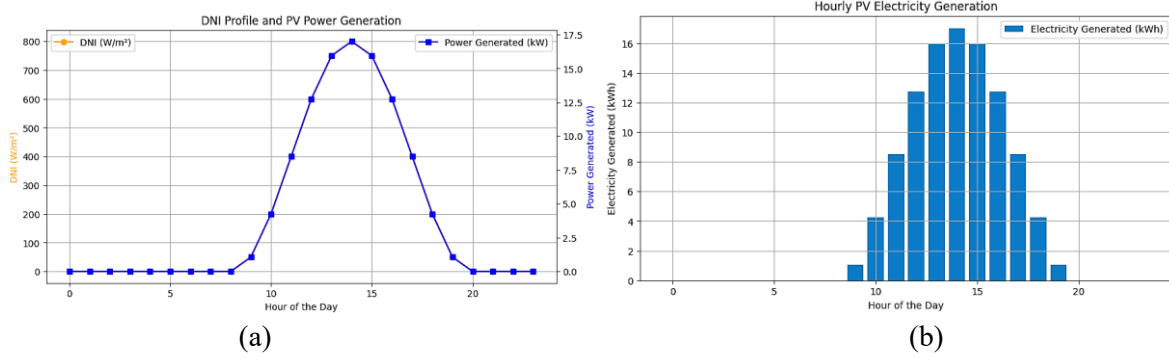


Figure 3. PV generation: (a) hourly DNI profile and corresponding PV power generation for the 25-kW PV system; (b) hourly PV electricity generation over the 24-hour simulation period.

Figure 3(b) presents hourly PV electricity generation. System generates a total of 102.00 kWh/day, with a maximum hourly electricity output of 17.00 kWh. Average PV power over full day ~ 4.25 kW, corresponding to a daily **capacity factor (CF)** of 17.00%. This confirms that PV system provides useful renewable contribution, although generation restricted to daytime window. From TE results, daily CAPEX allocation ~3.65 €/day & daily OPEX ~2.74 €/day, giving total daily PV cost 6.39 €/day. Based on daily generation of 102.00 kWh, resulting **levelized cost of electricity**, $LCoE_{PV} \sim 0.0627$ €/kWh (**equation (24)**). This low daily generation cost supports use of PV as a local renewable electricity source within the MG. However, due to mismatch between daytime PV generation and peak electricity-cost periods, BESS integration required shift part of the PV output toward peak-shaving operation.

3.3. BESS-Based PV Energy Shifting and Peak Shaving

BESS introduced to shift part of daytime PV electricity toward peak-demand or high-cost electricity periods. In this case study, BESS is not modelled as full backup system, rather as a peak-shaving/PV-shifting unit. This is more appropriate for the studied MG because the objective is to reduce grid-import exposure during expensive electricity hours rather than provide full-load autonomy. Lithium iron phosphate (LFP) lithium-ion was selected as BESS chemistry because its suitability for stationary storage applications, good cycle life, improved safety characteristics and declining cost [46]. This selection consists of recent storage literature and public energy-system datasets, where lithium-ion systems, particularly LFP, are widely represented for commercial and stationary battery storage applications [47].

BESS was sized for peak-shaving of 25 kW over a 3-hour discharge period, corresponding to delivered energy of 75 kWh (refer Table 4). With depth of discharge (DoD) ~0.85, round-trip efficiency (RTE) ~0.93 & temperature de-rating factor ~0.95, installed nominal battery capacity ~ 99.87kWh (**equation (6)**) [48]. The selected configuration represents a compact BESS unit of ~ 25 kW/100kWh, suitable for shifting a meaningful share of daily PV generation (102 kWh/day PV generation identified in Section 3.2) toward peak-demand or high-price periods [47, 48]. Part of Figure 4(a) exhibits main technical sizing indicators of the BESS. Installed nominal capacity is higher than required delivered energy because system accounts for DoD, round-trip efficiency & temperature derating. PCS power is 25kW, matching the selected peak-shaving power, while delivered energy per full cycle is 75kWh [46–48].

Table 4. Technical characteristics of the selected LFP BESS [46–48].

Parameter	Value
Battery chemistry	LFP lithium-ion
Application	Peak shaving
Peak shaving power	25 kW
Discharge duration	3.0 h
Required delivered energy	75 kWh
Installed nominal BESS capacity	99.87 kWh
Delivered energy per full cycle	75.00 kWh
PCS/inverter power	25 kW
Depth of discharge (DoD)	0.85
Round-trip efficiency	0.93
Temperature derating factor	0.95
Battery mass	832.25 kg
Cycle life	6000 cycles
Calendar lifespan	12 years

Table 5. Techno-economic specifications and cost parameters of the selected LFP peak-shaving BESS [46, 47].

Parameter	Value
Battery chemistry	LFP lithium-ion
BESS application	Peak shaving / PV energy shifting
Cost basis	Integrated installed BESS cost
Integrated BESS cost	280 €/kWh
Installed nominal BESS capacity	99.87 kWh
Initial integrated BESS CAPEX	€ 27,963.65EUR
Annual fixed OPEX	1.5% of CAPEX/year
Annual fixed OPEX	419.45 €/year
Project lifetime	15 years
Battery calendar lifespan	12 years
Replacement year	Year 12
Discount rate / WACC	5.00%
Salvage value	7.5% of initial CAPEX
Discounted replacement cost	€ 15,571.21
Discounted salvage value	€ 1,008.82
Annualized CAPEX	4,097.05 €/year
Daily CAPEX	11.22 €/day
Daily fixed OPEX	1.15 €/day
Total daily BESS cost	12.37 €/day
Discounted TCO	€ 46,879.82
$LCOS_{BESS}$	0.1650 €/kWh delivered

Table 5 presents the economic boundary and cost parameters of the selected LFP BESS. For the economic calculation, BESS cost was treated as an integrated installed system cost of 280 €/kWh. This value is assumed to include the battery system, power-conversion interface, control hardware, and installation-related balance-of-system contributions. Therefore, PCS/inverter and balance-of-system (BOS) and engineering, procurement and construction (EPC) costs were not added separately in order to avoid double counting. The installed BESS cost ~ 280 €/kWh, resulting an initial CAPEX of € 27,963.65. Figure 4(b) summarizes daily BESS cost breakdown. Daily CAPEX contribution ~11.22 EUR/day, while daily fixed OPEX =1.15 EUR/day. Resulting total daily BESS cost =12.37€/day, with a levelised cost of storage, $LCOS_{BESS}$ ~0.1650EUR/kWh delivered (equation (24)). These results show that economic performance of BESS mainly driven by capital cost, battery lifetime & replacement assumptions. Which is expected for stationary storage systems.

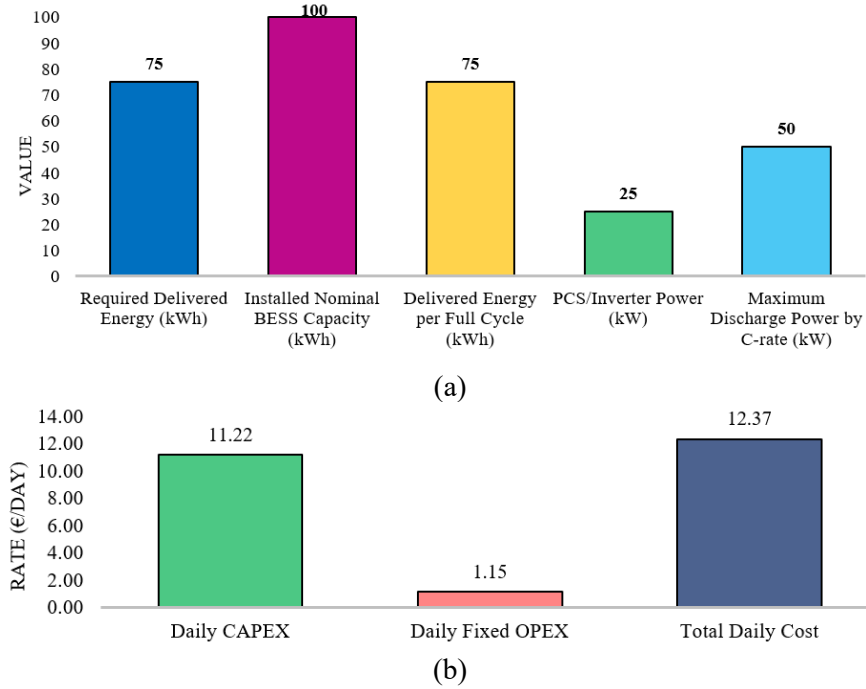


Figure 4. BESS: (a) technical sizing summary for PV energy shifting and peak shaving; (b) daily BESS cost breakdown for the selected LFP peak-shaving configuration.

3.4. MGT-Based Electrical and Thermal Power Generation

MGTs represent central dispatchable generation pillar of the proposed MG. Contrast to PV generation, which is governed by solar availability, BESS operation, is limited by stored energy capacity. But MGT cluster provides controllable power generation that can be scheduled according to day-ahead (DA) electrical demand profile. In addition to electricity production, MGT exhaust heat-recovery [heat exchanger \(HX\)](#) system provides a recoverable thermal-energy stream that can be integrated with heating pathways, GSHP source-side support, [borehole heat exchanger \(BHE\)](#) regeneration, or other low-grade heat utilization routes [17, 18, 49]. In this study, MGT operation evaluated through 03 main pathways. Pathway 1, MGTs supply 100% of electrical demand (P_{el}), while recoverable thermal energy (E_{th}) is reported but not allocated to thermal-demand (P_{th}) satisfaction. Pathway 2, MGTs supply full P_{el} , while P_{th} supplied through electricity-based heating. Pathway 3, MGTs supply P_{el} of microgrid together with additional electricity required for GSHP. These pathways allow the role of MGTs assessed not only as dispatchable electrical generators, but also flexible energy-conversion units within increasingly integrated electricity-heat supply configurations. [The hourly dispatch, fuel use and recoverable heat of each pathway are calculated with equations \(7\)–\(10\) and the daily costs with equations \(15\)–\(23\). The three pathways are MGT operating modes that serve as building blocks of the scenarios; their mapping to scenarios S1–S8 is given in Section 2.1 and Table 14.](#)

3.4.1. Pathway 1: MGT supply of 100% electrical demand without thermal-demand allocation.

Pathway-1, MGTs are scheduled to supply 100% P_{el} of MG, while recoverable heat from MGT heat-recovery/HX unit is not allocated to balance thermal-demand. This pathway therefore represents electricity-focused reference case of MGT operation. Scheduled fleet consists of 03 units 30, 65, 100kW, total installed dispatchable capacity of 195 kW. Main pathway-level operating TE results are summarized in Table 6. The Table 7 shows unit-level technical/cost contribution MGTs. Corresponding hourly dispatch, thermal recovery, fuel-cost, cost-breakdown profiles are presented in Figure 5(a)–(d). In Figure 5(a), MGT dispatch closely follows DA P_{el} profile. The P_{el} is 1387 kWh/day, MGTs generates 1404.7kWh/day. This gives a small oversupply ~ 17.7 kWh/day, corresponding to $\sim 1.3\%$ of demand, with zero unmet load. Indicates that selected 03-unit fleet is sufficient for full electrical autonomy in

this pathway, despite discrete unit capacities/part-load (PL) constraints. Stacked dispatch profile in Figure 5(b) and unit-level values in Table 7 show 100-kW is the dominant generator. It produces 830.4kWh/day, equivalent 59.1% of the total MGT electricity generation. The 65kW & 30kW units produce 340.4kWh/day & 233.9kWh/day, corresponding to 24.2% & 16.7%. Operating-count distribution further shows 30-kW operates for 13 unit-hours (U_{hour}), 65-kW for 8 U_{hour} & 100-kW unit for 9 U_{hour} . Thus, smaller unit provides low-load flexibility, while larger unit supplies the main energy share during high-demand periods.

Although the recoverable heat, Q_{rec} is not used for thermal-demand satisfaction, MGT Q_{rec} potential is substantial. Table 6 shows a peak Q_{rec} power $\sim 294.4 \text{ kW}_{\text{th}}$, an average $Q_{\text{rec}} \sim 122.0 \text{ kW}_{\text{th}}$ with total Q_{rec} of 2927.6kWh_{th}/day. This is also evident from Figure 5(c), where the Q_{rec} profile follows electrical dispatch pattern of Figure 5(a). Recoverable heat-to-electricity ($P_{\text{th}}/P_{\text{el}}$) ratio $\sim 2.08 \text{ kWh}_{\text{th}}/\text{kWh}_{\text{el}}$. Therefore, even in electricity-only pathway, MGT fleet produces large secondary thermal stream that can be used later by storing as geothermal energy. Fuel and carbon results in Table 6 show; fleet consumes 17,429MJ/day of biogas. Under adopted direct-emission accounting assumption, CO₂ emission cost is zero for 100% BG case. However, avoided CO₂ cost relative to a NG is 88.0 €/day. This confirms that fuel pathways strongly affect carbon-cost exposure of dispatchable MGTs, although overall result remains sensitive to assumed BG price. Cost decomposition in Table 7 and Figure 5(d) shows fuel cost (C_{fuel}) is the dominant cost component. Daily $C_{\text{daily}} \sim 348.6\text{€/day}$, compared with 58.3 €/day for annualized CAPEX & 52.6€/day for fixed OPEX. Total daily MGT cost $\sim 459.5\text{€/day}$, with no additional CO₂ cost with biogas assumption. When normalized by P_{el} , dispatch cost is 0.331€/kWh (on served demand.). At unit level, 100kW the largest $C_{\text{daily}} \sim 260.8\text{€/day}$ but also provides the largest energy contribution. Confirming unit-level cost understanding should based on both absolute cost & energy contribution not operating hours alone.

Table 6. Techno-economic summary of Pathway 1: pure MGT-based electrical dispatch without thermal-demand allocation.

Parameter	Symbol	Value
Total MGT capacity	$P_{\text{el,cap}}$	195 kW
Daily electrical demand	$E_{\text{el,demand}}$	$\approx 1387 \text{ kWh/day}$
MGT electrical generation	$E_{\text{el,total}}$	1404.7 kWh/day
Unmet demand	—	0 kWh/day
Net oversupply	—	17.7 kWh/day
Recoverable thermal energy	Q_{rec}	2927.6kWh _{th} /day
Peak recoverable thermal power	$P_{\text{th,rec,peak}}$	294.4 kW _{th}
Average recoverable thermal power	$P_{\text{th,rec,avg}}$	122.0 kW _{th}
Heat-to-electricity ratio	$Q_{\text{rec}}/E_{\text{el,total}}$	2.08 kWh _{th} /kWh _{el}
Biogas use	—	17,429 MJ/day
Fuel cost	$C_{\text{d,fuel}}$	348.6 €/day
Total MGT cost	$C_{\text{d,MGT}}$	459.5 €/day
Dispatch cost	—	0.331 €/kWh
Direct CO ₂ cost	$C_{\text{d,CO}_2}$	0 €/day
Avoided CO ₂ cost vs NG	—	88.0 €/day

Table 7. Unit-level technical and cost contribution of the three-unit MGT fleet under Pathway 1.

MGT class	E_{el}	Share of $E_{\text{el,total}}$	Q_{rec}	U_{hour}	$C_{\text{d,MGT}}$	Cost intensity
30 kW	233.9 kWh/day	16.70%	585.0 kWh _{th} /day	13	76.4 €/day	0.327 €/kWh _e
65 kW	340.4 kWh/day	24.20%	707.0 kWh _{th} /day	8	122.4 €/day	0.360 €/kWh _e
100 kW	830.4 kWh/day	59.10%	1635.6 kWh _{th} /day	9	260.8 €/day	0.314 €/kWh _e
Total	1404.7 kWh/day	100%	2927.6 kWh_{th}/day	30	459.5 €/day	0.327 €/kWh_e

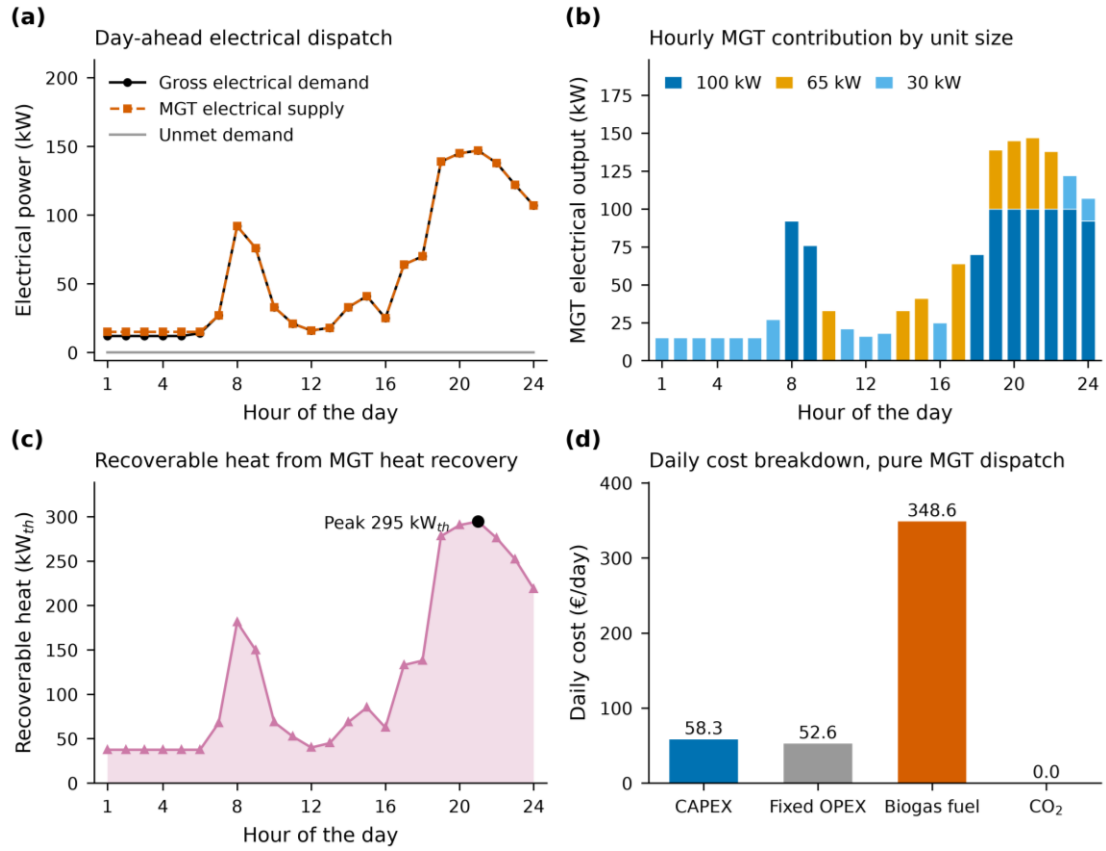


Figure 5. Pathway 1 MGT dispatch and techno-economic results: (a) MGT day-ahead electrical dispatch, (b) stacked hourly MGT electrical contribution by unit size, (c) hourly recoverable thermal power from the MGT heat-recovery/HX system and (d) daily cost breakdown. [Figure regenerated at 600 dpi from the hourly dispatch results.](#)

3.4.2. Pathway 2: MGT supply of 100% of the electrical demand including electric heating. Pathway-2 evaluates MGT-dominated configuration; MGT fleet supplies 100% of total P_{el} , including additional electricity required for electric-heating. Therefore, $P_{th,demand}$ is shifted to electrical load. The Q_{rec} from MGT [waste-heat recovery \(WHR\)](#) is separated, not directly credited to electric-heating balance. However, Q_{rec} stream is stored/injected into shallow-geothermal BHEs. Main TE results are summarized in Table 8, unit-level contributions presented in Table 9. Corresponding dispatch, Q_{rec} , cost profiles are shown in Figure 6(a)–(d).

Table 8. Main technical and techno-economic summary of Pathway 2.

Parameter	Symbol	Value
Total MGT capacity	$P_{el,cap}$	595 kW
Daily electrical demand	$E_{el,demand}$	9506 kWh/day
MGT electrical generation	$E_{el,total}$	9506 kWh/day
Recoverable thermal energy	Q_{rec}	17,209 kWh _{th} /day
Peak recoverable thermal power	$P_{th,rec,peak}$	1006 kW _{th}
Average recoverable thermal power	$P_{th,rec,avg}$	717 kW _{th}
Heat-to-electricity ratio	$Q_{rec}/E_{el,total}$	1.81 kWh _{th} / kWh _{el}
Biogas use	—	105,860 MJ/day
Fuel cost	$C_{d,fuel}$	2117.2 €/day
Total MGT cost	$C_{d,MGT}$	2392.9 €/day
Dispatch cost	—	0.252 €/kWh

Direct CO ₂ cost	C_{d,CO_2}	0 €/day
Avoided CO ₂ cost vs NG	—	534.5 €/day

Table 9. Compact unit-level contribution of the MGT fleet in Pathway 2.

MGT class	E_{el}	Share of $E_{el,total}$	Q_{rec}	U_{hour}	$C_{d,MGT}$	Cost intensity
30 kW	72 kWh/day	0.80%	181 kWh _{th} /day	4	34.5 €/day	0.479 €/kWh _{el}
65 kW	405 kWh/day	4.30%	840 kWh _{th} /day	9	128.0 €/day	0.316 €/kWh _{el}
100 kW	1223 kWh/day	12.90%	2410 kWh _{th} /day	14	327.1 €/day	0.267 €/kWh _{el}
2 × 200 kW	7806 kWh/day	82.10%	13,777 kWh _{th} /day	40	1903.3 €/day	0.244 €/kWh _{el}
Total	9506 kWh/day	100%	17,209 kWh _{th} /day	67	2392.9 €/day	0.252 €/kWh

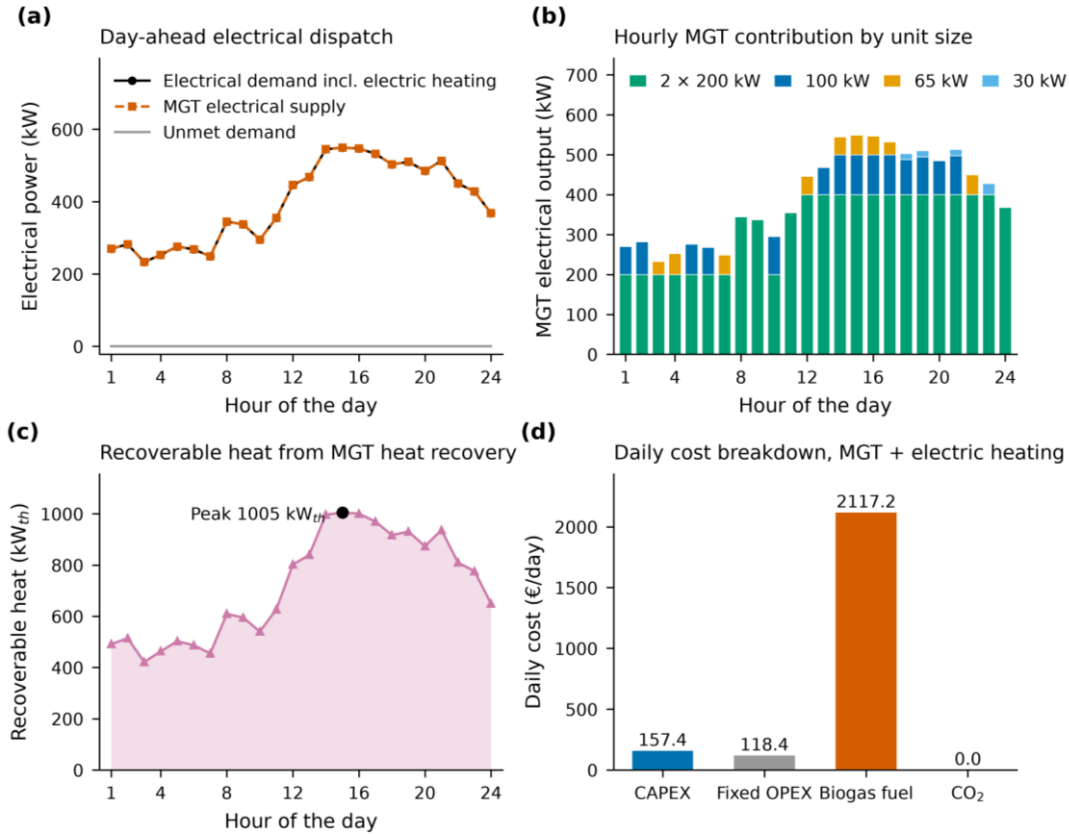


Figure 6. Pathway 2 MGT dispatch and techno-economic results: (a) MGT day-ahead electrical dispatch, (b) stacked hourly MGT electrical contribution by unit size, (c) hourly recoverable thermal power from the MGT heat-recovery/HX system and (d) daily cost breakdown.

Scheduled fleet of 05 MGT units/04 capacity classes: 30, 65, 100, 2×200kW, total $P_{el, cap} \sim 595$ kW. This larger fleet is required because P_{el} includes both base $P_{el, load}$ & electric-heating demand. During 24h period, total $E_{el, demand} \sim 9506$ kWh/day and MGTs generate exactly 9506 kWh/day. No unmet demand and no net daily oversupply occurred. Confirming selected 05-MGTs fully satisfy combined electrical/electric-heating load. Dispatch is dominated by 200 kW MGT. The 2 × 200kW generate 7806 kWh/day $\sim 82.1\%$ of $E_{el, total}$. The 100-kW generates 1223 kWh/day, 65- and 30-kW generate 405 & 72 kWh/day. Operating-count show same trend: fleet accumulates 67- U_{hour} , of which 200kW class accounts for 40- U_{hour} . Therefore, Pathway 2 shifts MGT operation from modular low-load tracking toward sustained operation of larger MGT units. Again, MGT-WHR/HX produces large recoverable thermal stream. Total $Q_{rec} \sim 17,209$ kWh_{th}/day, with a $P_{th, rec, peak} \sim 1006$ kW_{th} and $P_{th, rec, avg} \sim 717$ kW_{th}. The resulting $Q_{rec}/E_{el, total} \sim 1.81$ kWh_{th}/ kWh_{el}. Although this ratio is lower than Pathway 1, absolute Q_{rec} is much larger because total MGT generation & fuel throughput are significantly higher. At unit level,

200kW contributes 13,777 kWh_{th}/day, equal ~80.1% of total Q_{rec} , showing both electricity generation/ Q_{rec} mainly governed by largest MGT class.

Fleet consumes BG~105,860 MJ/day, with average fuel input intensity ~11.1 MJ/kWh_{el} and implied fleet-average η_{el} ~ 32%. Daily, $C_{d,fuel}$ ~2117.2 €/day. Fuel cost is again the dominant cost component, accounting 88.5% total $C_{d,MGT}$. Daily CAPEX/fixed OPEX contributions are 157.4 €/day & 118.4 €/day. Since 100% biogas is used, direct C_{d,CO_2} is zero, giving a total daily MGT cost of 2393 €/day. Normalized dispatch cost ~0.252 €/kWh, which is lower than Pathway 1 of 0.331 €/kWh, despite higher daily cost. This reduction occurs because the larger 200kW operates at higher utilization and dominates total energy supply. Therefore, Pathway-2 demonstrates a clear scale-utilization effect: increasing the dispatch level increases total fuel and operating cost but reduces specific cost when larger MGT units are efficiently utilized. Avoided CO₂ cost relative to a NG is 534.5 €/day, which is 6.1x higher than Pathway 1. This shows that fuel selection becomes increasingly important as MGT utilization/fuel throughput increases.

3.4.3. Pathway 3: MGT supply of 100% of the electrical demand and the GSHP operating electricity.

Pathway-3 evaluates integrated MGT–GSHP configuration which the MGTs supply 100% base P_{el} plus additional electricity for GSHP. Here, GSHP supplies 100% P_{th} while MGTs provides electrical input required for both microgrid & GSHP. The Q_{rec} from MGT-WHR is again treated separately. This Q_{rec} is directed to shallow geothermal BHE for GSHP source-side operation or other thermal integrations. Main pathway-results summarized in Table 10, compact unit-level contribution presented in Table 11. With dispatch, Q_{rec} , cost profiles shown in Figure 7(a)–(d).

Table 10. Techno-economic summary of Pathway 3.

Parameter	Symbol	Value
Total MGT capacity	$P_{el,cap}$	395 kW
Daily electrical demand	$E_{el,demand}$	3707 kWh/day
MGT electrical generation	$E_{el,total}$	3707 kWh/day
Recoverable thermal energy	Q_{rec}	6739 kWh _{th} /day
Peak recoverable thermal power	$P_{th,rec,peak}$	460 kWkW _{th}
Average recoverable thermal power	$P_{th,rec,avg}$	281 kWkW _{th}
Heat-to-electricity ratio	$Q_{rec}/E_{el,total}$	1.82 kWh _{th} /kWh _{el}
Biogas use	—	41,419 MJ/day
Fuel cost	$C_{d,fuel}$	828.4 €/day
Total MGT cost	$C_{d,MGT}$	1021.7 €/day
Dispatch cost	—	0.276 €/kWh
Direct CO ₂ cost	C_{d,CO_2}	0 €/day
Avoided CO ₂ cost vs NG	—	209.1 €/day

Table 11. Unit-level contribution of the MGT fleet in Pathway 3.

MGT class	E_{el}	Share of $E_{el,total}$	Q_{rec}	U_{hour}	$C_{d,MGT}$	Cost intensity
30 kW	42 kWh/day	1.10%	105 kWh _{th} /day	2	28 €/day	0.667 €/kWh _{el}
65 kW	139 kWh/day	3.80%	289 kWh _{th} /day	3	69 €/day	0.496 €/kWh _{el}
100 kW	594 kWh/day	16.00%	1169 kWh _{th} /day	7	187 €/day	0.315 €/kWh _{el}
200 kW	2932 kWh/day	79.10%	5176 kWh _{th} /day	17	738 €/day	0.252 €/kWh _{el}
Total	3707 kWh/day	100%	6739 kWh_{th}/day	29	1021.7 €/day	0.276 €/kWh

Compared with Pathway-2, Pathway-3 substantially reduces P_{el} assigned to MGT fleet because P_{th} is supplied by GSHP rather than direct electric heating, $EL_{heating}$. Total $E_{el,demand}$ ~3707 kWh/day including base MG+GSHP $P_{el,demand}$. This is 5799 kWh/day lower than Pathway 2, that is 61.0% reduction relative to $EL_{heating}$ pathway. However, remains higher than Pathway-1 because GSHP introduces an additional P_{el} .

Scheduled fleet contain 4-MGTs (30,65,100 & 200kW) with total $P_{el,cap} \sim 395$ kW. Over 24h's MGT fleet generates ~ 3707 kWh/day with zero unmet demand and no net oversupply (Figure 7(a)–(b)). The 4-unit fleet fully satisfy combined MG+GSHP $P_{el,demand}$ without grid import/excess generation. The dispatch structure is dominated by 200kW, generating 2932kWh/day or $\sim 79.1\%$ of total $E_{el,total}$. The 100kW contributes 594 kWh/day, while 65- and 30-kW units generate 139 & 42kWh/day. Operating-count distribution follows same pattern (Figure 7(b)): fleet accumulates 29- U_{hour} of operation, out of those 200kW accounts ~ 17 U_{hour} . Therefore, once GSHP P_{el} is added to base $P_{el,demand}$ dispatch shifts toward higher utilization of largest MGT, smaller units mainly provide residual load tracking. MGT-WHR produces 6739kWh_{th}/day of Q_{rec} with a $P_{th,rec,peak} \sim 460$ kW_{th} and $P_{th,rec,avg} \sim 281$ kW_{th}. Resulting $Q_{rec}/E_{el,total} \sim 1.82$ kWh_{th}/kWh_e (Figure 7(c)). At unit level, 200kW provides 5176kWh_{th}/day, or 76.8% of total Q_{rec} , showing that both electricity generation and Q_{rec} production is strongly governed by largest unit (Table 11).

MGT fleet consumes BG $\sim 41,419$ MJ/day, with average fuel input intensity of 11.17MJ/kWh_{MJ} per kWh_{el} and an implied fleet-average; $\eta_{el} \sim 32.2\%$. The $C_{d,fuel} \sim 828.4$ €/day. Fuel cost is again the dominant cost component, accounting $\sim 81.1\%$ of total $C_{d,MGT}$. Daily CAPEX/fixed OPEX contributions are 107.9€/day & 85.5€/day (Figure 7(d)). Since 100% BG used, C_{d,CO_2} is zero & total $C_{d,MGT} \sim 1021.7$ €/day. Resulting dispatch cost ~ 0.276 €/kWh when normalized by $E_{el,demand}$. This places Pathway 3 between electricity-only pathway (P1) & direct-EL_{heating} pathway (P2). Compared with Pathway 1, GSHP increases MGT $P_{el,load}$, fuel consumption, recoverable heat & total $C_{d,MGT}$. Compared with Pathway-2, replacing EL_{heating} with GSHP reduces required MGT electrical generation & total $C_{d,MGT}$. Avoided CO₂ cost relative to a NG case ~ 209.1 €/day, showing that carbon-cost benefit of BG operation remains significant under GSHP-integrated pathway.

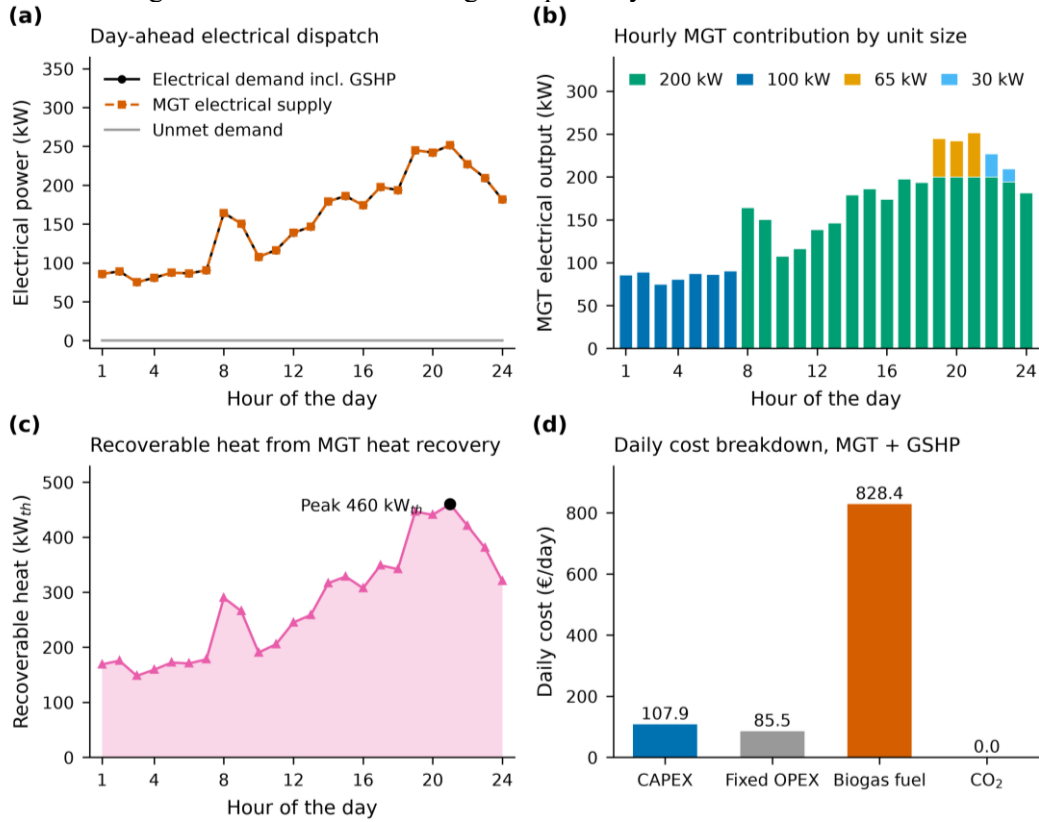


Figure 7. Pathway 3 MGT dispatch and techno-economic results: (a) MGT day-ahead electrical dispatch, (b) stacked hourly MGT electrical contribution by unit size, (c) hourly recoverable thermal power from the MGT heat-recovery/HX system and (d) daily cost breakdown.

3.5. Comparative TEA of Selected Thermal Power Pathways

Thermal demand of MG assessed comparing 04 P_{th} pathways: electric heating/electric boiler, NG-boiler, BG-boiler, GSHP. Each technology sized for same installed $P_{th} \sim 580 \text{ kW}_{th}$ and evaluated for 15-year lifetime (n) with a $r \sim 5\%$. Purpose of comparison is to identify which pathway provides the most favourable balance between cost, emissions/energy-security performance under selected case-study assumptions (see Table 12).

Table 12. Main input assumptions for the thermal-demand pathway comparison.

Parameter	Electric boiler	NG-boiler	BG-boiler	GSHP
Installed heating capacity	580 kW_{th}	580 kW_{th}	580 kW_{th}	580 kW_{th}
Economic lifetime	15 years	15 years	15 years	15 years
Discount rate ($r\%$) / WACC	5.00%	5.00%	5.00%	5.00%
Efficiency / COP	0.98	0.89	0.88	3.5
Energy price (base)	0.030 €/MJ	0.017 €/MJ	0.022 €/MJ	0.030 €/MJ
Unit CAPEX	140 €/kW _{th}	170 €/kW _{th}	175 €/kW _{th}	275 €/kW _{th}
Total CAPEX	€ 81,200	€ 98,600	€ 101,500	€ 159,500
Fixed OPEX	1.5%/year	2.0%/year	2.0%/year	2.5%/year
CO ₂ cost	- €/day	165.81 €/day	- €/day	- €/day
Served heat fraction	100%	100%	100%	100%

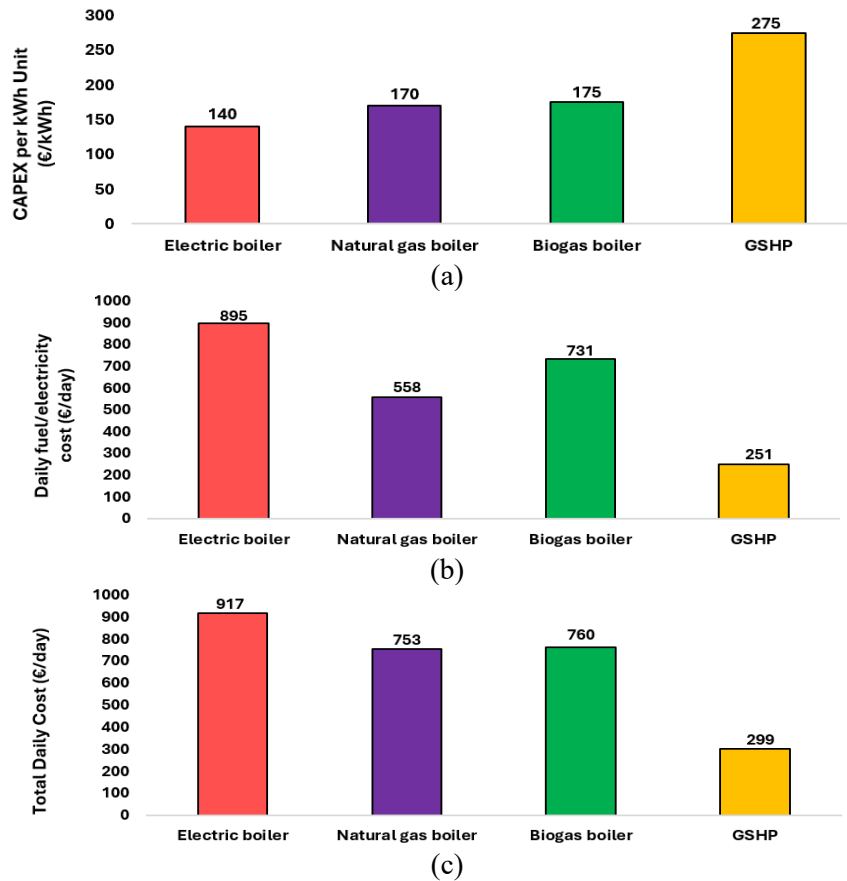


Figure 8. Capital and daily cost comparison of thermal-demand pathways: (a) unit CAPEX by technology, (b) daily fuel/electricity cost by technology and (c) total daily thermal catering cost by technology.

Capital-cost comparison is shown in Figure 8(a). Electric heating/boiler has the lowest unit CAPEX $\sim 140 \text{ €/kW}_{th}$ followed by NG-boiler $\sim 170 \text{ €/kW}_{th}$ and BG-boiler $\sim 175 \text{ €/kW}_{th}$. GSHP has the

highest unit CAPEX~275 €/kW_{th}, resulting the largest total installed CAPEX of €159,500. However, this cost does not account for geothermal drilling/borehole implementation costs, they assumed incentivized. If drilling/borehole costs considered, this comparison would become impossible and unmatched due to extremely substantial drill/borehole construction costs associated with GSHP's. Therefore, from a pure investment-cost perspective, electric heating appears attractive, while GSHP requires the highest upfront investment. However, this capital-cost ranking changes substantially when daily operating cost and levelized heat cost (LCoH) are considered.

Figure 8(b) compares daily fuel/electricity cost of each heating-pathway. Electric-heating has the highest daily energy cost ($C_{day,Energy_cost}$) of 894.75€/day because it directly converts high-value electricity into heat. BG-boiler has second-highest $C_{day,Energy_cost}$ ~730.71€/day, followed by NG-boiler $C_{day,Energy_cost}$ ~558.30€/day. In contrast, GSHP has the lowest $C_{day,Energy_cost}$ ~250.53€/day due to its COP~3.50, which reduces required P_{el} for same delivered Q_{demand} . This shows GSHP pathway converts a higher initial CAPEX into substantially lower operating cost. Figure 8(c) presents total daily thermal catering cost (C_{th_daily}). Electric-boiler is the most expensive pathway, with a C_{th_daily} ~917.37€/day. NG & biogas boilers have similar C_{th_daily} of 752.93 €/day & 760.38 €/day. Although NG-boiler has a lower energy cost than BG-boiler, its daily CO₂ cost~165.81€/day offsets much of this advantage. GSHP provides the lowest C_{th_daily} ~299.34 €/day, making it the most economically favourable heating pathway in this case study.

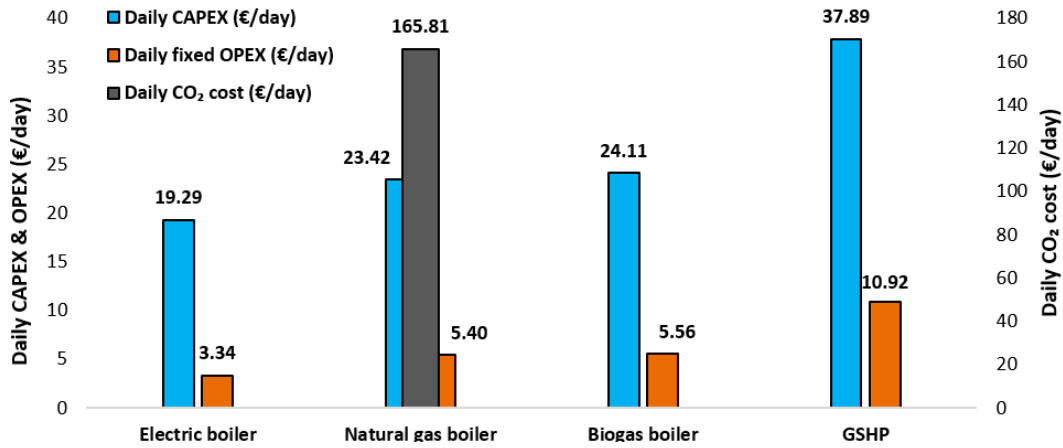


Figure 9. Daily cost-component breakdown of thermal-demand pathways.

Table 13. Summary of thermal pathway techno-economic results.

Parameter	Electric boiler	Natural gas boiler	Biogas boiler	GSHP
Daily CAPEX (€/day)	19.29	23.42	24.11	37.89
Daily fixed OPEX (€/day)	3.34	5.40	5.56	10.92
Daily fuel/electricity cost (€/day)	894.75	558.3	730.71	250.53
Daily CO ₂ cost (€/day)	0.0	165.81	0.0	0.0
Total daily cost (€/day)	917.37	752.93	760.38	299.34
Levelized heat cost (LCoH) [€/kW _{th}]	0.113	0.093	0.094	0.037
Daily CO ₂ emissions (t/day)	0	1.84	0	0

Under selected model boundary, electric-heating, BG-boiler & GSHP have zero CO₂ emissions as their emission factors were set to zero in the input assumptions. NG-boiler having direct operational CO₂ emissions, reach highest emission levels during peak- P_{th} hours. Over full-day, NG-boiler emits 1.84 tCO₂/day, results daily CO₂ cost~165.81€/day. Confirming carbon pricing significantly affects competitiveness of fossil-based thermal pathways. Figure 9 provides daily cost-component breakdown. For all technologies, dominant cost component is “fuel/electricity” cost rather than CAPEX or fixed OPEX. This is especially clear for electric-boiler, where energy-cost dominate C_{th_daily} . For NG-boiler,

CO₂ cost is also significant, represents an additional penalty that is absent in BG and GSHP. For GSHP, although CAPEX & fixed OPEX are higher than the boiler alternatives, the much lower energy-consumption cost dominates the final economic outcome.

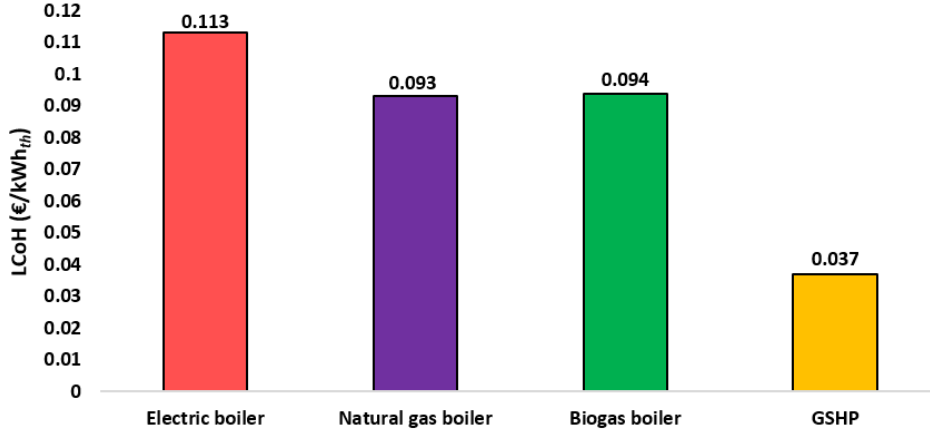


Figure 10. Levelized cost of heat (LCoH_{th}) comparison by heating technology.

The levelised cost of heat, LCoH_{th} comparison in Figure 10 confirms same ranking. GSHP has the lowest heat cost 0.037€/kWh_{th}, followed by NG-boiler~0.093€/kWh_{th}, BG-boiler~0.094 €/kWh_{th}, & Electric-heating~0.113 €/kWh_{th}. Therefore, under selected assumptions, GSHP reduces LCoH_{th} by 67% compared with electric-heating and by 60% compared with both boiler-based options.

3.6. Comparison of the eight energy-supply scenarios

Figure 11 and Table 14 compare the daily energy-supply cost of the eight evaluated scenarios (S1–S8). The results show that the economic performance of a microgrid is strongly governed by the selected thermal pathway, rather than by electrical self-supply alone. The grid-only case with subsidy (S1) gives a $C_{daily} \sim 1064 \text{ €/day}$, whereas the grid-only case without subsidy (S2) increases to 1730€/day. This difference of 666€/day shows the strong influence of electricity price-support mechanisms on end-user affordability. Therefore, subsidized-grid represents a policy-supported low-cost reference, while the non-subsidized-grid case represents the cost exposure that may occur under full market-price conditions. The highest cost is obtained for MG-only electricity/thermal scenario (S3) at 2116€/day. This is 98.9% higher than subsidized-grid-only case and 22.3% higher than non-subsidized-grid-only case. Although this pathway offers the highest degree of local energy autonomy, it places both electrical & thermal supply burden on microgrid, increasing MGT fuel-consumption and $C_{dailyOPEX}$. Therefore, 100% microgrid-only operation is technically feasible but economically weak unless Q_{th} is fully credited, fuel-price is reduced, or additional value is obtained from resilience, backup operation, or electricity-market participation. MG + grid electric-heating scenario (S4) reduces $C_{daily} \sim 1258 \text{ €/day}$. This is 40.5% lower than MG-only pathway, still 18.2% higher than subsidized-grid-only case. Result confirms that direct electric-heating reduces microgrid fuel burden compared with 100% MGT-based P_{th} supply but remains exposed to electricity-price volatility. Therefore, electric heating provides a simple thermal pathway, but not the most robust economic option when heating demand is large.

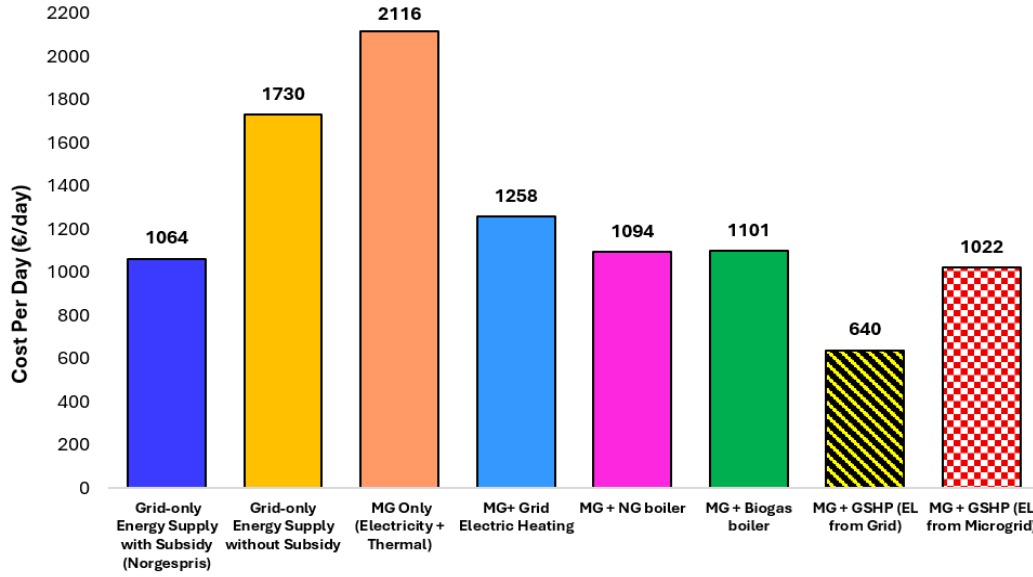


Figure 11. Final comparison of daily energy-supply cost (€/day) for the **eight** evaluated scenarios (S1–S8, from left to right).

Table 14. Scenario-to-pathway mapping and daily and annualised energy-supply cost of the 08 scenarios (annualised with equation (25)).

Scenario	Electrical supply	Thermal supply	Daily cost (€/day)	Annualised cost (k€/year)	Δ vs S1 (%)	Δ vs S2 (%)
S1	Grid (with price support)	Grid electric heating	1,064	388.4	–	-38.5
S2	Grid (without price support)	Grid electric heating	1,730	631.5	+62.6	–
S3	PV + BESS + MGT, Pathway 2	Electric heating, MGT electricity	2,116	772.3	+98.9	+22.3
S4	PV + BESS + MGT, Pathway 1	Electric heating, grid electricity	1,258	459.2	+18.2	-27.3
S5	PV + BESS + MGT, Pathway 1	NG boiler	1,094	399.3	+2.8	-36.8
S6	PV + BESS + MGT, Pathway 1	BG boiler	1,101	401.9	+3.5	-36.4
S7	PV + BESS + MGT, Pathway 1	GSHP, grid electricity	640	233.6	-39.8	-63.0
S8	PV + BESS + MGT, Pathway 3	GSHP, MGT electricity	1,022	373.0	-3.9	-40.9

MG+NG-boiler (S5) & MG+BG-Boiler (S6) scenarios present similar $C_{\text{daily}} \sim 1094$ & 1101 €/day, respectively. These values are only 2.8% & 3.5% higher than subsidized-grid-only case, but 36.8% & 36.4% lower than non-subsidized grid-only case. This indicates that boiler-assisted microgrid configurations can approach subsidized-grid cost levels while substantially reducing exposure to non-subsidized electricity prices. NG-boiler gives a slightly lower C_{daily} than BG-boiler, with difference ~ 7 €/day. However, NG pathway remains exposed to fossil-fuel price variation and carbon-cost penalties, whereas BG pathway provides a lower-carbon thermal route with only a small cost increase. Thus, NG–BG comparison represents a direct trade-off between marginal cost reduction & carbon-policy resilience. The lowest C_{daily} obtained for MG+GSHP scenario (S7) supplied by grid-electricity, at 640€/day. This is 40% lower than the subsidized-grid-only case & 63.0% lower than non-subsidized-grid-only case. The large reduction is caused by high conversion efficiency of GSHP, where P_{th} is supplied with much lower P_{el} input than direct electric heating. Compared with MG+grid electric-heating, GSHP-grid reduces C_{daily} by 618€/day, comparable to 49.1% reduction. This confirms that HP integration is the strongest operational cost-reduction mechanism among the evaluated thermal pathways. MG+GSHP supplied from the microgrid (S8) gives $C_{\text{daily}} \sim 1022$ €/day. This is slightly lower than subsidized-grid-only case by 42€/day, or 3.9% and its 41% lower than non-subsidized grid-only case. This margin is, however, small and sensitive to the price assumptions (Section 3.7). Although it is more expensive than grid-supplied GSHP, it provides a higher level of local energy control because GSHP P_{el} supplied by microgrid. Therefore MG+GSHP-from-microgrid represents a more balanced solution. It does not achieve the minimum C_{daily} , but it combines cost competitiveness, reduced grid-

price exposure, dispatchable local generation, and thermal-sector coupling. Overall, Figure 11 shows that microgrid feasibility depends on thermal integration. A microgrid without an efficient thermal pathway becomes the most expensive option, while the same microgrid concept combined with GSHP operation becomes one of the most competitive pathways. This demonstrates that electrical microgrid design & heating-system design cannot be evaluated independently. Specially with significant global warming and in colder-climate regional applications, the thermal pathway controls a large share of the final cost outcome.

A key limitation of GSHP comparison is that the MG+GSHP scenario does not include drilling, BHE, geological investigation, or ground-loop BHE costs. Therefore, the reported 640€/day & 1022€/day values should be interpreted as operational and system-level cost indicators, not complete installed-cost results. Nevertheless, the result is important because it identifies GSHP integration as the strongest long-term pathway if ground-infrastructure costs can be reduced, shared, or supported. Public-sector mechanisms, such as municipal participation [50], low-interest green loans [51], infrastructure-sharing models [52], or partial subsidy of drilling/ BHE installation, could therefore become decisive for future microgrid–GSHP deployment [53].

The broader implication is that policy and infrastructure design are as important as component selection [54, 55]. The subsidized-grid-only case appears economically attractive, but it does not provide local resilience or reduced market exposure. The non-subsidized grid-only case shows the vulnerability of end users to electricity-price volatility. Boiler-assisted microgrids provide cost stability but remain dependent on fuel pathway and carbon assumptions. Full MGT-based supply provides energy autonomy but at high daily cost. The GSHP-integrated pathways offer the strongest cost reduction, especially when electricity price support is available or when microgrid electricity can be supplied at competitive cost.

The final message of the comparison is therefore that hybrid MGs should not be assessed as electricity-only systems. Their value emerges when PV, BESS, dispatchable BG-fuelled MGTs, heat-recovery, GSHP & policy-sensitive electricity prices are evaluated together. In this framework, most promising future pathway is not the highest-autonomy case, but the configuration that balances cost, resilience, decarbonization & thermal efficiency. The results suggest that PV–BESS–MGT microgrids coupled with GSHP-infrastructure can provide a practical transitional route toward secure, flexible, and lower-carbon local energy systems, provided that the site-specific ground-infrastructure cost is addressed through suitable financing or policy support.

3.7. Sensitivity analysis of key assumptions

A one-at-a-time sensitivity analysis was carried out to test the robustness of the scenario ranking with respect to the assumptions that most influence the results: grid electricity price, biogas price, natural gas price and CO₂ price (each $\pm 20\%$), CAPEX of the MGT and thermal-supply equipment ($\pm 20\%$), discount rate (3% and 7% instead of 5%), GSHP COP (3.0 and 4.0 instead of 3.5) and daily thermal demand ($\pm 20\%$), the last of which is used as a first-order proxy for the seasonal variation of heating demand. Each parameter was varied while all others were kept at their base values. The scenario costs were perturbed component-wise using the cost breakdowns in Tables 6–13: fuel, electricity and CO₂ costs were scaled with the respective price, annualized CAPEX with the CAPEX factor or with the ratio of capital recovery factors ($\text{CRF}(3\%)/\text{CRF}(5\%) = 0.87$ and $\text{CRF}(7\%)/\text{CRF}(5\%) = 1.14$), GSHP electricity with 3.5/COP and energy-related costs with the thermal demand. Grid electricity in S1 and S2 was split into building and heating electricity according to the daily demands (85.7% for heating), MGT fuel use was taken as proportional to MGT generation, and cost terms not explicitly resolved in Tables 6–13 were kept constant. The results are summarized in Table 15 and Figure 12.

Table 15. One-at-a-time sensitivity of the daily energy-supply cost of each scenario (17 cases: base case and 16 parameter variations).

Scenario	Base (€/day)	Range (€/day)	Most influential parameter	Swing (€/day)
S1	1064	851–1277	Grid electricity price $\pm 20\%$	426
S2	1730	1384–2076	Grid electricity price $\pm 20\%$	692
S3	2116	1742–2490	Biogas price $\pm 20\%$	749

S4	1258	1079–1437	Grid electricity price $\pm 20\%$	358
S5	1094	949–1239	Thermal demand $\pm 20\%$	290
S6	1101	885–1317	Biogas price $\pm 20\%$	432
S7	640	570–710	Biogas price $\pm 20\%$	139
S8	1022	856–1188	Biogas price $\pm 20\%$	331

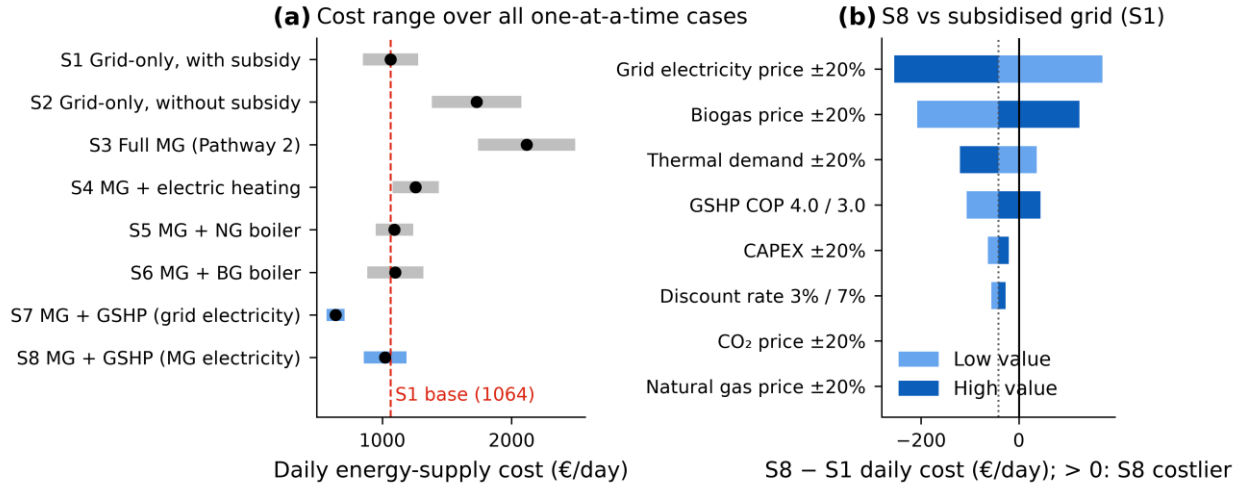


Figure 12. One-at-a-time sensitivity analysis: (a) range of the daily energy-supply cost of each scenario over all parameter variations (dots: base case; dashed line: S1 base cost); (b) effect of each parameter on the cost difference between S8 and S1 (dotted line: base-case difference of -42 €/day; ‘low’ and ‘high’ refer to the first and second value given for each parameter).

Across all 17 cases, the MG + grid-supplied GSHP scenario (S7) remains the lowest-cost option (570–710 €/day) and the full-MG scenario (S3) remains the most expensive (1742–2490 €/day), so the main conclusions of Section 3.6 are robust to the tested assumptions. The grid-only references are governed by the electricity price (S1: 851–1277 €/day; S2: 1384–2076 €/day). Scenarios S3, S6, S7 and S8 are most sensitive to the biogas price, because fuel accounts for 76–89% of the daily MGT cost, whereas S4 is most sensitive to the electricity price and S5 to the thermal demand. In contrast, the small advantage of the microgrid-supplied GSHP scenario (S8) over the subsidised grid (S1), 42 €/day in the base case, is not robust: S8 becomes more expensive than S1 when the grid electricity price is 20% lower (+171 €/day), the biogas price is 20% higher (+124 €/day), the GSHP COP is 3.0 (+44 €/day) or the thermal demand is 20% lower (+37 €/day) (Figure 12(b)). Similarly, the 7 €/day difference between the NG-boiler (S5) and BG-boiler (S6) scenarios reverses when the biogas price decreases or the natural gas or CO₂ price increases by 20%. CAPEX and discount-rate variations change the daily costs by at most 3%, confirming that operating energy costs dominate the economics. Hence, the advantage of GSHP integration is robust, whereas the case for microgrid-supplied GSHP operation depends on secure, low-cost biogas supply, efficient heat-pump operation and the future evolution of grid-price support.

4. Limitations of the study

The results should be interpreted within the following limitations. Several of them lie outside the aims and scope of this conference study, which is to establish a consistent hourly techno-economic comparison of PV–BESS–MGT microgrid pathways with alternative thermal-supply options, and they will be addressed in the authors’ ongoing extended work.

- **Temporal representation:** Annual values are obtained by scaling a representative 24-hour day (equation (25)), so the seasonal variation of PV output, electricity prices, electrical demand and heating demand is not resolved explicitly. The $\pm 20\%$ thermal-demand and price variations in Section 3.7 indicate that the ranking of the lowest-cost (S7) and highest-cost (S3) scenarios is unaffected, but annual cost magnitudes and the S8–S1 comparison are. Because PV supplies

only about 102 kWh/day ($\approx 7\%$ of the electrical demand), its seasonal variation has a limited effect on the comparison, whereas the higher winter heating demand increases the absolute advantage of efficient thermal pathways. A full-year (8760 h) simulation or a representative-day approach with typical and extreme days [44, 45] based on Nordic seasonal price and demand data will be reported in a subsequent study.

- **Uncertainty analysis:** The sensitivity analysis is deterministic and one-at-a-time; parameter interactions and probabilistic uncertainty are not captured. A risk-informed Monte Carlo analysis, as applied in the authors' previous work [19], is planned for the extended study.
- **Ground infrastructure:** The GSHP pathways exclude drilling, borehole heat exchanger, geological investigation and ground-loop costs (Section 3.6); the GSHP results are therefore operational and system-level cost indicators rather than complete installed-cost results.
- **Thermal storage representation:** Storage of recovered MGT heat in shallow geothermal boreholes is represented as an available energy stream; the transient ground-temperature response, storage losses and the resulting COP improvement are not simulated dynamically. Coupling the present framework with the authors' detailed borehole models [20, 49] is outside the scope of this paper.
- **Lifetime economic indicators:** The NPV, PBP and ROI formulation (Eq's: (14) & (26)–(29)) is defined, but this paper reports daily and annualised costs; a full discounted cash-flow comparison including replacements, degradation and cost escalation will be reported separately.
- **MGT and policy modelling:** MGTs are modelled with constant rated electrical efficiencies and a rule-based unit-commitment heuristic, without PL efficiency curves, start-up costs or ramping limits, and electricity-price support and carbon prices are fixed at their base-case levels. The results refer to a single Norwegian case study and should be transferred to other climates and markets with care.

5. Future Studies

Future studies should extend the present TEA framework by including life-cycle cost and circular-economy indicators. While this paper evaluates CAPEX, OPEX, fuel/electricity cost, carbon cost, and operational scenario performance, a full sustainability comparison should also consider raw material extraction, transport, processing, manufacturing, recycling, and final waste handling after the system lifetime. This is especially relevant for PV modules, BESS, power electronics, and GSHP-related infrastructure, where material separation and recycling may require significant energy and cost. Therefore, future work should combine the present dispatch-based TEA with life-cycle costing and life-cycle assessment to capture the complete economic and environmental burden from manufacturing to end-of-life management.

6. Conclusions

This study presented an integrated techno-economic assessment of PV–BESS–MGT microgrid pathways with alternative thermal-supply configurations, grid support, and electricity trading. The analysis connected hourly dispatch modelling with scenario-level cost comparison to evaluate how local generation, storage, dispatchable MGT operation, fuel choice, heat recovery, GSHP integration, and electricity-price support influence the economic feasibility of building-scale microgrids.

The results show that PV provides a low-cost local renewable contribution, while BESS improves system flexibility by enabling PV energy shifting and peak-shaving support. However, the main dispatchable role is carried by the MGT fleet. The MGT results confirm that mixed-capacity MGT clusters can meet the required electrical demand with zero unmet load across the evaluated pathways. In the electricity-only pathway, the three-MGT fleet supplied 1387 kWh/day at a dispatch cost of 0.331 €/kWh, while also producing 2927.6 kWh/day of recoverable heat. When electric-heating demand was added, the larger five-MGT fleet supplied 9506 kWh/day, reducing the specific dispatch cost to 0.252 €/kWh due to higher utilization of the 200 kW units, but increasing total daily cost because of the much larger fuel requirement. In the GSHP-integrated pathway, the four-MGT fleet supplied 3707 kWh/day

at 0.276 €/kWh, demonstrating that GSHP operation substantially reduces the electrical burden compared with direct electric heating.

The thermal pathway comparison showed that heating-system selection strongly controls the final microgrid economics. Direct electric heating had the highest daily thermal cost, while NG and biogas boilers provided intermediate-cost solutions. GSHP achieved the lowest thermal cost due to its COP advantage, despite having higher equipment CAPEX than boiler-based alternatives. This confirms that thermal efficiency is more important than initial equipment cost when the system is evaluated under daily operating-cost conditions.

The final scenario comparison showed that microgrid feasibility is not determined by electrical self-supply alone. The grid-only case with subsidy cost 1064 €/day, while the non-subsidized grid-only case increased to 1730 €/day, showing the strong influence of policy support. The full MG-only electricity and thermal pathway was the most expensive option at 2116 €/day, because it placed the full electrical and thermal burden on the microgrid. Boiler-assisted MG pathways were close to the subsidized grid reference, with 1094 €/day for NG boiler and 1101 €/day for biogas boiler. The lowest daily cost was obtained for the MG + GSHP pathway supplied from grid electricity, at 640 €/day, while the MG-supplied GSHP pathway reached 1022 €/day and remained slightly below the subsidized grid-only reference. The sensitivity analysis confirmed that S7 remains the lowest-cost and S3 the highest-cost scenario under $\pm 20\%$ variations of the key assumptions, whereas the small margin of the MG-supplied GSHP pathway over the subsidized grid depends on the electricity and biogas prices and on the GSHP COP.

The main conclusion is that hybrid microgrids should not be evaluated as electricity-only systems. Their value emerges from the combined interaction of PV generation, BESS flexibility, dispatchable MGT operation, recoverable heat, thermal-supply technology, electricity-price exposure, and policy conditions. Among the evaluated pathways, GSHP-integrated configurations provide the strongest operational cost advantage, while MGT-based microgrids provide dispatchability, resilience, and heat-recovery potential. However, the GSHP results should be interpreted with caution because drilling, BHE installation, geological investigation, and ground-loop infrastructure costs were not included, and annual values were derived from a representative day (Section 4). Therefore, public-sector support, shared ground-infrastructure models, green financing, or targeted subsidies may be decisive for making future MG–GSHP systems bankable.

Overall, this study shows that the most promising pathway is not necessarily the configuration with the highest autonomy, but the one that balances cost, resilience, decarbonization, and thermal efficiency. PV–BESS–MGT microgrids coupled with efficient GSHP-based thermal supply can provide a practical transition route toward secure, flexible, and lower-carbon local energy systems, particularly under uncertain electricity prices, escalating geo-political tensions and evolving policy conditions for an energy resilient future.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

This study was funded by the GeoSUSTAIN Project. The GeoSUSTAIN project is funded by CETPartnership, the Clean Energy Transition Partnership under the 2024 joint call for research proposals, co-funded by the European Commission (GA No. 101069750) and with the funding organisations detailed on <https://cetpartnership.eu/calls/joint-call-2024/funding-organisations>



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