MRes Thesis Paper

University of Hertfordshire

COST OF FLEXIBILITY IN NGCC-CCS PLANTS: THERMAL ENERGY STORAGE VERSUS GRID-SCALE BATTERY STORAGE

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Parts of the work presented in Chapters 3, 4 and 5 have been accepted for presentation and forthcoming publication in the following conference contribution:

- Payel, N.U., Eltaweel, M. and Wu, H., 2026. *Recovering Flexibility in CCS-Retrofitted Gas Plants: Comparing plant-integrated TES and grid-scale BESS using net £/MWh-flex*. SPECS 2026, University of Hertfordshire. Accepted conference contribution; publication forthcoming.

A journal manuscript based on this research is being prepared for submission to a peer-reviewed energy journal:

- Payel, N.U., Eltaweel, M. and Wu, H., manuscript in preparation. *Marginal Cost of Flexibility in UK NGCC Plants with CCS: Plant-Integrated TES versus Grid-Scale BESS*. Intended submission to a peer-reviewed energy journal.

These outputs are reported here to identify the dissemination pathway for the research. The thesis remains the governing academic submission, and the full methods, assumptions, numerical results and limitations are those presented in the thesis chapters.

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ABSTRACT

Great Britain's transition towards a low-carbon electricity system increases the need for flexibility alongside variable renewable generation. In natural gas combined-cycle (NGCC) plants equipped with post-combustion carbon capture and storage (CCS), steam extraction for solvent regeneration couples heat demand with electrical output. This thesis compares plant-integrated thermal energy storage (TES) supplying the CCS reboiler with grid-scale lithium-ion battery energy storage systems (BESS) operating at the electrical interface. The analysis uses marginal cost of flexibility (MCF), defined as average incremental net cost per credited MWh-flex. TES flexibility is calculated from useful reboiler heat through an electrical-equivalent conversion factor; BESS flexibility is measured as AC electrical output.

The study combines existing HOMER operating records with chronological storage calculations and financial assessment on an 8% real discount-rate basis over 25 years. Under the four-hour TES reference case, p40/p60 dispatch thresholds and an installed-cost assumption of £40/kWh-th, TES provides 12,776.80 MWh-flex annually at £42.91/MWh-flex. This cost includes charging opportunity cost and useful-discharge electricity value. The 100 MWh and 200 MWh headline BESS cases, each with a 50 MW converter, yield £54.41 and £58.49/MWh-flex, respectively. A separate SOC-constrained, price-responsive BESS sensitivity yields £50.13 and £59.85/MWh-flex under its own operating and accounting assumptions. With the headline BESS assumptions held fixed, TES installed-cost parity occurs at approximately £46.52/kWh-th and £48.83/kWh-th against the two respective BESS cases.

TES therefore has the lower calculated reference MCF under the specified screening assumptions. The comparison remains conditional on physical integration, electrical headroom, dispatch, accounting scope and the retained price–thermal alignment limitation. An illustrative headroom restriction reverses the headline ordering. The study contributes an application of chronological storage accounting to CCS reboiler heat shifting, an installed-cost parity analysis and a comparison of the specified storage cases within explicit physical and economic boundaries.

TABLE OF CONTENTS

PLAGIARISM STATEMENT ii

DECLARATION OF ORIGINALITY iii

ABSTRACT 4

TABLE OF CONTENTS 5

LIST OF FIGURES 10

LIST OF TABLES 12

LIST OF ABBREVIATIONS AND NOMENCLATURE 14

Abbreviations 14

Nomenclature and symbols 16

Units and suffixes 19

Subscripts and superscripts used in equations 20

1. INTRODUCTION 21

1.1 UK energy transition and the flexibility challenge 21

1.2 Role of NGCC in a decarbonising electricity system 22

1.3 Integrating CCS with NGCC: emerging flexibility constraints 23

1.4 System level flexibility requirements in GB 24

1.5 TES as a plant level flexibility option 25

1.5.1 TES technology relevant to NGCC+CCS system 26

1.5.2 Technical requirements favouring sensible TES for NGCC+CCS 27

1.6 BESS as a system-level comparator 29

1.6.1 BESS architecture and grid integration 29

1.6.2 BESS deployment in GB 30

1.7 Research gap 31

1.8 Aim, research questions and objectives 32

1.9 Scope and boundaries 33

1.10 Novel contributions and thesis structure 34

1.10.1 Novel contributions 34

1.10.2 Thesis structure 35

2. LITERATURE REVIEW 36

2.1 NGCC with CCS: performance and cost characteristics 36

2.1.1 Baseline NGCC+CCS configuration and system boundaries 36

2.1.2 Technology maturity and readiness of NGCC+CCS 37

2.1.3 Thermodynamic performance impacts of CCS integration 38

2.1.4 Steady-state capture and cost assumptions 39

2.1.5 Typical utilisation assumptions and their limitations 40

2.2 NGCC+CCS flexibility and operational constraints 41

2.3 Plant-level flexibility options for NGCC+CCS 43

2.3.1 Solvent storage and flexible regeneration concepts 43

2.3.2 Capture-rate modulation and bypass strategies 44

2.3.3 Steam bypass and alternative heat-supply concepts 44

2.3.4 Process-level modifications to reduce energy penalty 45

2.4 TES integration in NGCC+CCS plants: retrofit context 46

2.4.1 Operating modes of retrofitted NGCC+CCS plants with TES 46

2.4.2 Techno-economic implications of TES retrofitting 47

2.4.3 TES comparison boundary and integration limitations 49

2.5 BESS as a system-level flexibility resource 49

2.5.1 Role of BESS in power-system flexibility 50

2.5.2 Role of BESS in low-inertia power systems 50

2.5.3 Grid services provided by BESS 51

2.5.4 Sizing, siting, and operational constraints of BESS 53

2.5.5 Techno-economic characteristics of BESS 54

2.5.6 BESS in GB and its relationship to plant-integrated TES 54

2.6 Comparative gaps and research positioning 55

2.6.1 Flexibility constraints in NGCC-CCS systems 56

2.6.2 Research gap and thesis scope 56

3. METHODOLOGY 58

3.1 Modelling 58

3.1.1 HOMER PRO modelling 59
3.1.2 Input data 60
3.2 Model case structure 65
3.3 Flexibility and cost formulation 66
3.3.1 Annualisation 66
3.3.2 Marginal cost of flexibility 67
3.3.3 TES heat-shifting 68
3.3.4 BESS cost 72
3.3.5 Comparative ratio 73
3.4 Sensitivity and uncertainty analysis 74
3.5 Internal consistency checks 78
3.6 Modelling scope and limitations 79
4. RESULTS AND DISCUSSION 82
4.1 Baseline case results 82
4.2 TES pathway results 85
4.3 BESS pathway results 90
4.4 Central cost comparison 95
4.5 Sensitivity and uncertainty results 97
4.5.1 TES dispatch-threshold sensitivity 97
4.5.2 Reboiler-load-shape sensitivity 98
4.5.3 TES storage-duration sensitivity 98
4.5.4 One-at-a-time sensitivity analysis 99
4.5.5 TES CAPEX × BESS NPC parity mapping 101
4.5.6 Monte Carlo uncertainty analysis 102
4.6 Internal consistency checks 103
4.7 Discussion and chapter synthesis 103
5. CONCLUSION 106
5.1 Response to the research questions 106
5.2 Limitations 107
5.3 Contribution of the study 109

5.4 Future work **110**

5.5 Closing conclusion **111**

REFERENCES **112**

APPENDIX **115**

APPENDIX A: HOMER Pro simulation output evidence **115**

APPENDIX B: Python post-processing pipeline **119**

B.1 Pipeline overview and rationale **119**

B.2 Module architecture **120**

B.3 Data inputs **121**

B.4 Flexibility service denominator **122**

B.5 Annualisation and economic reporting **122**

B.6 Calculation sequence **123**

B.7 Environment and dependencies **123**

APPENDIX C: TES reduced-order proxy algorithm specification **124**

C.1 Rationale for the reduced-order TES proxy **124**

C.2 Algorithm specification **124**

C.2.1 Supporting annual TES operating-pattern visualisations 125

C.3 TES vessel sizing and cost basis **127**

C.4 Turbine penalty factor **127**

C.5 Scope limits of the proxy **128**

APPENDIX D: Adopted numerical inputs and configuration **129**

D.1 Financial, generator and CCS parameters **129**

D.2 TES parameters **130**

D.3 BESS parameters **130**

D.4 Sensitivity and Monte Carlo settings **131**

APPENDIX E: Internal consistency evidence **133**

E.1 Checking structure 133
E.2 Numerical reconciliation and energy-balance checks 133
E.3 Reference calculation summary 134
APPENDIX F: Model algorithm listings 135
F.1 TES proxy algorithm 135
F.2 BESS post-processing algorithm 135
F.3 Deterministic sensitivity, parity and Monte Carlo algorithm 136
F.4 Internal-check algorithm 136
APPENDIX G: Plantflex-lab interactive research demonstrator 138
G.1 Purpose and status 138
G.2 Prototype screening functions 138
G.3 Access and development status 138

LIST OF FIGURES

Fig. 1-1: Thermal-energy-storage categories, indicative operating-temperature ranges and technology-readiness levels (IRENA, 2020). 26
Fig. 1-2: Main components and grid integration of a BESS, showing battery modules, power conversion system, transformer, switchgear, and utility interface (Kozich, 2024) 30
Fig. 1-3: UK Cumulative commissioned BESS capacity, the project pipeline, and the 2030 national target (Hutters, 2025) 31

Fig. 2-1: NGCC plant with post-combustion CO_2 capture, showing the GT–HRSG–ST arrangement and solvent-regeneration steam extraction (Alruwaili et al., 2025). 37
Fig. 2-2: Indicative technology-readiness levels for CO_2 capture, transport, storage and utilisation technologies (Wang et al., 2024). 38
Fig. 2-3: NGCC with post-combustion CO_2 capture, showing low-pressure steam extraction for solvent regeneration and the resulting heat–power coupling (Hughes et al., 2023). 42
Fig. 2-4: Thirty-year NPV comparison of TES configurations for the NETL B31B NGCC–CCS plant using NYISO electricity prices (Limb et al., 2022). 48
Fig. 2-5: Monthly GB BESS benchmark revenues by market stream, November 2024 to November 2025 (Modo Energy). 52

Fig. 3-1: Methodology workflow showing how HOMER evidence and adopted assumptions are processed through the Python calculation workflow. 58
Fig. 3-2: Conceptual NGCC+CCS configuration with plant-integrated TES for reboiler heat; electrical and feedwater systems are shown in simplified form. 59
Fig. 3-3: HOMER Pro model schematic and external TES proxy boundary. 60
Fig. 3-4: TES reference dispatch thresholds in the adopted 8,760-hour price series: p40 = £69/MWh for charging and p60 = £79/MWh for discharging. 68
Fig. 3-5: Sensitivity and uncertainty analysis framework adopted in the study. 76

Fig. 4-1: Case 0 generator output against grid price under the prescribed thermal-demand scenario. 84
Fig. 4-2: Grid-price distribution during boiler idle and boiler firing periods 85
Fig. 4-3: Representative weekly TES operating profile under the p40/p60 reference rule 88
Fig. 4-4: Annual TES operating profile under the p40/p60 reference rule. 89
Fig. 4-5: Annual operating profile of BESS-100, the lowest-NPC configuration among the capacities tested in HOMER. 92
Fig. 4-6: BESS marginal cost of flexibility before and after the benchmark-based non-wholesale revenue adjustment. 94
Fig. 4-7: Reference-case MCF for four-hour TES and retained BESS configurations. 95
Fig. 4-8: One-at-a-time MCF sensitivity to selected input parameters. 100

Fig. 4-9: Algebraic sensitivity of the TES/BESS-100 MCF ratio to TES installed cost and the aggregate BESS incremental-NPC multiplier. 101
Fig. 4-10: Distribution of the TES/BESS-100 MCF ratio across 10,000 illustrative input scenarios. 102

Fig. A-1: HOMER Pro cost summary for Case 0 no-storage NGCC+CCS baseline 116
Fig. A-2: Retained HOMER converter-output summary for BESS-100 (100 MWh, 50 MW). ... 117
Fig. A-3: Representative weekly operating profile of the retained 100 MWh BESS case. 118

Fig. B-1: Conceptual organisation of Python post-processing. Table B-1 identifies the module names and calculation roles used in the revised pipeline. 120

Fig. C-1: Annual TES SOC occupancy for the 4 h p40/p60 reference case. Near-empty and near-full states are defined as SOC values within 1% of the usable vessel limits. 126
Fig. C-2 Annual TES SOC carpet plot for the 4 h p40/p60 reference case, showing hourly vessel occupancy by day of year and hour of day 126

LIST OF TABLES

Table 1-1: UK electricity generation mix in 2024 (DESNZ, 2025c). 22
Table 1-2: Indicative technology-readiness level, duration and round-trip-efficiency ranges for selected storage technologies Compiled from (IRENA, 2020, 2017). 25
Table 1-3: Simplified comparison of TES technology families relevant to reboiler-side CCS heat shifting. 28

Table 2-1: Reported thermodynamic performance of NGCC plants with and without post-combustion CCS. 39
Table 2-2: Dominant cost components of NGCC+CCS under steady operation based on Rahmanta et al. (2025) and Alruwaili et al. (2025). 40
Table 2-3: Utilisation, financial and emissions considerations in the NGCC+CCS assessment by Hersbach et al. (2025). 41
Table 2-4: Impact of process-level modifications on NGCC+CCS performance. 45
Table 2-5: TES-enabled operating modes for reboiler-side thermal shifting. 47
Table 2-6: Frequency stability challenges in low-inertia power systems and corresponding BESS support functions. 51
Table 2-7: Key BESS revenue streams relevant to GB grid-scale battery operation. 53
Table 2-8: Conceptual comparison of plant-integrated TES and grid-scale BESS as flexibility pathways. 55

Table 3-1: Principal input data and modelling assumptions. 62
Table 3-2: Model case structure, tool boundary and analytical role. 65
Table 3-3: Staged uncertainty analysis framework. 75
Table 3-4: Sensitivity and Monte Carlo ranges. 76
Table 3-5: Internal consistency checking methods. 78

Table 4-1: Case 0 no-storage baseline results. 83
Table 4-2: TES chronological reference-case operation and net cost. 86
Table 4-3: Heat-demand multiplier comparison with proportionally resized four-hour TES. 87
Table 4-4: BESS operation and revised financial results. 90
Table 4-5: Battery and converter replacement schedules over the 25-year comparison. 91
Table 4-6: SOC-constrained, price-responsive BESS sensitivity. 93
Table 4-7: BESS MCF before and after the benchmark-based non-wholesale revenue adjustment. 94
Table 4-8: Reference-case marginal cost comparison. 95
Table 4-9: Fixed-schedule TES electrical-credit diagnostic under illustrative additional-headroom limits. 96
Table 4-10: TES threshold sensitivity. Panel A reports MCF (£/MWh-flex) for all 25 combinations; Panel B reports selected symmetric cases. 97

Table 4-11: Prescribed reboiler-load-shape sensitivity. 98
Table 4-12: TES storage-duration sensitivity from 1 to 72 hours. 99
Table 4-13: One-at-a-time sensitivity results. 100
Table 4-14: TES installed cost at equal MCF for selected BESS cost assumptions. 101
Table 4-15: Monte Carlo results under the illustrative input distributions. 102
Table 4-16: Chapter 4 result synthesis. 104

Table 5-1: Principal limitations of the study. 107

Table A-1: Retained HOMER summary results for the Case 0 baseline. 115
Table A-2: Retained HOMER summary results for the BESS configurations. 116

Table B-1: Python modules and calculation roles. 120
Table B-2: Principal input classes used by the Python workflow. 121
Table B-3: MWh-flex denominator definitions used in the Python workflow. 122
Table B-4: Annualised cost treatment used in the post-processing workflow. 122
Table B-5: Main Python environment and dependency requirements. 123

Table C-1: Chronological hourly SOC-constrained TES reduced-order proxy algorithm. 124
Table C-2: TES reference sizing, cost and diagnostic basis. 127

Table D-1: Financial, generator and CCS reference assumptions. 129
Table D-2: TES input parameters and derived reference-case quantities. 130
Table D-3: BESS assumptions and calculation boundaries. 131
Table D-4: Deterministic sensitivity and Monte Carlo settings. 131

Table E-1: Numerical reconciliation and storage energy-balance discrepancies. 133
Table E-2: Reference calculation summary. 134

Table G-1: Prototype functions of PlantFlex Lab. 138

LIST OF ABBREVIATIONS AND NOMENCLATURE

This section lists the abbreviations, technical terms and symbols used in the thesis. Symbols are grouped with their definitions and units where applicable. Units are reported in the same form used in the methodology and results chapters.

Abbreviations

AC	Alternating current
BESS	Battery Energy Storage System
BMRS	Balancing Mechanism Reporting Service
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2	Carbon dioxide
CRF	Capital Recovery Factor
CSV	Comma-separated values
DC	Direct current
DESNZ	Department for Energy Security and Net Zero
DPA	Dispatchable Power Agreement
EFC	Equivalent Full Cycles
EMS	Energy Management System
GB	Great Britain
GBP	Pound sterling
HOMER	Hybrid Optimization of Multiple Energy Resources
HRSG	Heat Recovery Steam Generator
IEAGHG	IEA Greenhouse Gas R&D Programme
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LAES	Liquid Air Energy Storage
LCOS	Levelised Cost of Storage
LCOE	Levelised Cost of Electricity
MCF	Marginal Cost of Flexibility
MEA	Monoethanolamine
MIP	Market Index Price
MWh-flex	Credited flexible electrical energy, expressed in megawatt-hours
NESO	National Energy System Operator
NGCC	Natural Gas Combined Cycle
NPC	Net Present Cost
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance

OAT	One-at-a-time
OPEX	Operating expenditure
PCS	Power Conversion System
RTE	Round-trip Efficiency
SOC	State of Charge
TES	Thermal Energy Storage
TRL	Technology Readiness Level
UK	United Kingdom
UKERC	UK Energy Research Centre
VRE	Variable Renewable Energy
YAML	YAML configuration file format

Nomenclature and symbols

Symbol	Meaning	Unit
t	Hourly time step	h
p_t	Grid electricity price in hour t	£/kWh
p_{ch}	TES charging-price threshold	£/kWh
p_{dis}	TES discharging-price threshold	£/kWh
α	TES shift fraction	fraction
$P_{base,t}$	Base plant-output proxy in hour t	kW
f_{reb}	Reboiler heat factor applied to the base plant-output proxy	kWth/kWe
f_{HS}	Heat-stress multiplier applied to the reboiler-load proxy	fraction
$Q_{reb,t}$	Case 0 hourly CCS solvent-regeneration reboiler-load proxy	kWh-th
$Q_{ch,req,t}$	Requested TES thermal charging energy in hour t, before vessel constraints	kWh-th
$Q_{ch,acc,t}$	Accepted TES thermal charging energy in hour t, after vessel constraints	kWh-th
$Q_{spill,t}$	Curtailed TES charging opportunity in hour t because the requested charge cannot be accepted	kWh-th
$Q_{dis,req,t}$	Requested useful TES discharge to the CCS solvent-regeneration reboiler in hour t	kWh-th
$Q_{dis,use,t}$	Useful TES discharge supplied to the CCS solvent-regeneration reboiler in hour t after vessel constraints	kWh-th
$Q_{unmet,t}$	Unmet TES discharge request in hour t because the requested useful discharge cannot be supplied	kWh-th
SOC_t	TES thermal state of charge at the end of hour t	kWh-th
$Q_{ch,req,ann}$	Annual requested TES thermal charging energy	kWh-th/yr
$Q_{ch,acc,ann}$	Annual accepted TES thermal charging energy	kWh-th/yr
$Q_{spill,ann}$	Annual curtailed TES charging opportunity	kWh-th/yr
$Q_{dis,use,ann}$	Annual useful TES discharge supplied to the CCS solvent-regeneration reboiler	kWh-th/yr
$Q_{unmet,ann}$	Annual unmet TES discharge request	kWh-th/yr
$Q_{loss,ann}$	Annual TES thermal loss attributable to storage inefficiency	kWh-th/yr
η_{TES}	TES thermal round-trip efficiency	fraction
η_{ch}	TES charging efficiency	fraction
η_{dis}	TES discharging efficiency	fraction
φ_{te}	Thermal-to-electric conversion factor used to calculate electricity foregone during accepted TES charging and electricity retained during useful TES discharge	kWe/kWth
h_{TES}	TES storage duration	h

Symbol	Meaning	Unit
c_{TES}	TES unit installed capital cost	£/kWh-th
E_{TES}	TES usable thermal-energy capacity	kWh-th
$P_{TES,max}$	Maximum TES thermal charging or discharging rate	kWth
R_{ret}	Retention of useful TES discharge relative to the unconstrained annual-balance proxy	%
N_{EFC}	Equivalent full TES cycles completed during the modelled year	cycles/yr
ε_{cyc}	Cyclic annual TES state-of-charge closure error	kWh-th
$MWh_{flex,TES}$	Annual TES-enabled electrical-equivalent flexibility arising from avoided contemporaneous reboiler steam extraction	MWh-flex/yr
$E_{inv,AC}$	Annual BESS AC inverter output exported to the grid	kWh/yr
$MWh_{flex,BESS}$	Annual BESS market-facing flexible electricity	MWh-flex/yr
P_{conv}	BESS converter rating	MW
NPC_{BESS}	Net present cost of the BESS case	£
NPC_0	Net present cost of the no-storage Case 0 baseline	£
ΔNPC_{BESS}	Incremental BESS net present cost above Case 0	£
Δt	Duration of each model time step	h
$C_{asset,TES}$	Annual TES asset-cost component comprising annualised capital cost and fixed O&M	£/yr
$C_{opp,ch}$	Annual electricity opportunity cost of accepted TES charging	£/yr
$V_{eq,dis}$	Annual value of electricity retained through useful TES discharge	£/yr
C_{TES}	Annual TES net cost, including charging opportunity cost and useful-discharge electricity value	£/yr
$C_{ann,BESS}$	Annualised incremental BESS cost, including external fixed O&M, before the non-wholesale revenue adjustment	£/yr
C_{nw}	Annual headline BESS non-wholesale revenue adjustment	£/yr
$C_{net,BESS}$	Annual net BESS cost after the non-wholesale revenue adjustment	£/yr
$C_{O\&M,BESS}$	External annual BESS operation and maintenance allowance added during post-processing	£/yr
c_{nw}	Annual headline BESS non-wholesale revenue adjustment per unit converter capacity	£/MW/yr
Ccap,TES	Installed TES capital cost	£
$Qdis,ann^{AB}$	Annual useful TES discharge calculated under the unconstrained annual-balance benchmark	kWh-th/yr
Cj	Annual net cost attributed to flexibility pathway j	£/yr
MWhflex,j	Annual credited flexible electricity output attributed to pathway j	MWh-flex/yr
$MCF_{gross,BESS}$	BESS marginal cost of flexibility before the non-wholesale revenue adjustment; wholesale trading cash flows remain included	£/MWh-flex

Symbol	Meaning	Unit
$MCF_{\mathbf{TES}}$	TES marginal cost of flexibility based on annual net cost	£/MWh-flex
$MCF_{\mathbf{BESS}}$	Headline BESS marginal cost of flexibility after the non-wholesale revenue adjustment	£/MWh-flex
$R_{\mathbf{TES/BESS}}$	Ratio of TES net marginal cost of flexibility to headline BESS marginal cost of flexibility	dimensionless
$C_{\mathbf{ann}}$	Annualised capital cost	£/yr
C_{capex}	Initial capital cost	£
$MCF_{\mathbf{j}}$	Marginal cost of flexibility for pathway j	£/MWh-flex
$C_{O\&M,\mathbf{TES}}$	Annual fixed TES operation and maintenance cost	£/yr
CRF	Capital recovery factor	dimensionless
r	Real discount rate	fraction
n	Project lifetime	yr
N	Number of Monte Carlo samples	samples
$N_{TES<\mathbf{BESS}}$	Number of Monte Carlo samples in which TES MCF is lower than the corresponding headline BESS MCF	samples

Units and suffixes

£	Pound sterling monetary value
£/kWh	Pound sterling per kilowatt-hour
£/MWh-flex	Pound sterling per megawatt-hour of credited flexible electricity
h	Hour
yr	Year
cycles/yr	Equivalent full cycles per year
kW	Kilowatt
MW	Megawatt
kWh	Kilowatt-hour
MWh	Megawatt-hour
GWh	Gigawatt-hour
kWe	Kilowatt-electric
kWth	Kilowatt-thermal
kWh-th	Kilowatt-hour thermal
MWh-flex	Megawatt-hour of credited flexible electricity

Subscripts and superscripts used in equations

AC	Alternating-current grid-side output
acc	Accepted after application of the TES vessel constraints
nw	Non-wholesale revenue adjustment
ann	Annual value
asset	TES asset-cost component
base	Base plant-output proxy
BESS	Battery energy storage system pathway
ch	Charge / charging
conv	Converter
cyc	Cyclic annual state-of-charge closure
dis	Discharge / discharging
EFC	Equivalent full cycles
eq	Electrical-equivalent value
flex	Credited flexible electricity output
gross	BESS cost before the non-wholesale revenue adjustment, including wholesale trading cash flows
HS	Assumed elevated reboiler heat-demand multiplier
inv	Inverter
loss	Storage loss
max	Maximum value or rate
net	Net annual-cost basis after the applicable revenue or value adjustment
opp	Charging opportunity cost
reb	CCS solvent-regeneration reboiler
req	Requested before application of the TES vessel constraints
ret	Retention relative to the unconstrained annual-balance proxy
spill	Requested TES charging rejected because of charging-rate or storage-capacity constraints
t	Hourly time step
te	Thermal-to-electric conversion / turbine-penalty factor
TES	Thermal energy storage pathway
unmet	Requested TES discharge not delivered because of insufficient stored energy or the discharge-rate constraint
use	Useful TES discharge supplied to the CCS solvent-regeneration reboiler
AB	Unconstrained annual-balance benchmark retained only for the retention comparison
cap	Capital cost
j	Generic flexibility pathway

1. INTRODUCTION

1.1 UK energy transition and the flexibility challenge

The drive to limit global warming to well below 2 °C, with efforts towards 1.5 °C, as set out in the Paris Agreement, places rapid electricity-sector decarbonisation at the centre of national climate strategies (IPCC, 2023). The UK embedded this obligation in domestic law through the Climate Change Act 2008 and the Climate Change Act 2008 (2050 Target Amendment) Order 2019, which increased the statutory 2050 emissions-reduction target from 80% to 100% relative to the 1990 baseline ("The Climate Change Act," 2008). Scientific assessments in the IPCC Sixth Assessment Synthesis Report underline that achieving these goals requires deep reductions in power-sector emissions well before mid-century, because low-carbon electricity is a prerequisite for decarbonising transport, buildings and industry (IPCC, 2023).

In response, the UK has introduced a sequence of policy milestones shaping the future electricity system. The Clean Power 2030 Action Plan: A New Era of Clean Electricity defines a clean-power system as one in which low-carbon sources provide at least 95% of annual generation in a typical weather year and generate at least as much electricity as Great Britain consumes over the year. The plan retains a limited role for unabated gas as reserve capacity to protect security of supply. It also identifies power CCUS as a low-carbon dispatchable technology supported through the Dispatchable Power Agreement, enabling generation to operate behind renewables but ahead of unabated gas (DESNZ, 2024). Alongside the Clean Power 2030 pathway, DESNZ identifies power CCUS as part of the route to power-sector decarbonisation by 2035, subject to security of supply. Analysis cited by DESNZ suggests that up to 10 GW of power CCUS could be needed by 2035 (DESNZ, 2023).

The real challenge arises because this shift brings not only more clean energy, but also greater intermittency and more demanding system-level balancing requirements. Wind output fluctuates with weather systems, creating steep ramps in net demand as generation rises and falls over a few hours, while solar introduces strong diurnal swings and can drive low net loads around midday followed by sharp evening ramps. Britain's Electricity Explained, 2024 Review identifies periods of high renewable penetration, low net demand and increasing curtailment when network or system constraints bind (NESO, 2025). Future Energy Scenarios and the Clean Flexibility Roadmap indicate that higher renewable penetration increases the need for flexibility across multiple timescales (DESNZ, 2025a; National Grid ESO, 2024).

Future system planning retains a portfolio of flexibility resources, including storage, interconnection, demand-side response and dispatchable low-carbon generation, rather than relying on short-duration batteries alone (National Grid ESO, 2024).

1.2 Role of NGCC in a decarbonising electricity system

Despite rapid growth in renewable generation, gas remains a major contributor to the UK electricity mix. In 2024, gas-fired generation supplied approximately one-third of total electricity output, even as wind and solar reached record levels of penetration. This reflects the continued structural reliance on dispatchable thermal generation to maintain system security during periods of low renewable availability, prolonged cold spells and sharp demand ramps (DESNZ, 2025b).

Table 1-1 presents the 2024 UK electricity-generation mix and shows the continued contribution of gas alongside the growing share of wind, solar and other low-carbon sources.

Table 1-1: UK electricity generation mix in 2024 (DESNZ, 2025c).

Generation source	Share of electricity generation (%)
Wind and solar	34.3
Gas	30.4
Nuclear	14.2
Other renewables	14.1
Hydro	2.0
Oil and other fuels	4.2
Coal	0.7

Looking ahead, national system studies consistently retain NGCC capacity within credible net-zero pathways, albeit with declining annual load factors. Analyses in GB's Electricity Explained and the Future Energy Scenarios indicate that gas-fired generation increasingly shifts from baseload and mid-merit operation toward a residual balancing role, operating less frequently overall but providing firm, dispatchable capacity during hours or days when wind and solar output is insufficient (National Grid ESO, 2024; NESO, 2025).

Within this context, NGCC remains relevant to the UK's decarbonisation pathway, but its long-term role depends on deep emissions reduction and enhanced operational flexibility. Clean Power 2030 planning retains power CCUS as a route to firm low-carbon generation (DESNZ, 2024). Integrating post-combustion CCS into NGCC plants introduces additional thermodynamic and operational constraints, particularly through the coupling between solvent-regeneration heat demand and the steam cycle. This motivates an assessment of plant-integrated TES and grid-scale BESS as distinct flexibility pathways. Their credited flexible electricity is expressed in MWh-flex: for TES, this is the electrical output retained through reduced reboiler steam extraction during useful discharge; for BESS, it is the accumulated AC inverter output exported to the grid. These quantities are defined in Equations 3-20 and 3-31, respectively.

1.3 Integrating CCS with NGCC: emerging flexibility constraints

CCS refers to the capture of CO_2 emissions from sources such as power plants and industrial processes, followed by transport and permanent storage in deep geological formations (DESNZ, 2023).

Post-combustion amine absorption is the most commercially mature and retrofit-compatible pathway for existing power plants. In this configuration, CO_2 is absorbed from the flue gas in an absorber column and subsequently released in a stripper (desorber) through the application of low-pressure steam. The resulting CO_2 stream is then dried, compressed and transported for storage. Auxiliary equipment and CO_2 compression impose additional electrical loads on the plant (Hughes et al., 2023; IEAGHG, 2024). A prominent UK development is Net Zero Teesside Power, which entered the execution phase in December 2024 and aims to become the world's first gas-fired power station with carbon capture and storage (Net Zero Teesside Power, 2024). However, this configuration also creates a tight coupling between solvent-regeneration heat demand and the steam cycle, which has important implications for plant-level operational flexibility.CCS provides a means of reducing emissions from fossil-fuelled electricity generation (IPCC, 2023). The reference NGCC+CCS configuration adopted in this study assumes capture of 90% of the CO_2 entering the capture process (Alruwaili et al., 2025, Table 1). This capture fraction is distinct from the reduction in emissions per unit of electricity generated, which also depends on the energy penalty associated with capture. UK policy retains power CCUS as a low-carbon dispatchable option supported through the Dispatchable Power Agreement (DESNZ, 2024). These plants are expected to operate flexibly rather than as baseload, modulating output to complement variable renewable generation.

However, integrating post-combustion CCS with NGCC introduces a significant energy penalty. Net electrical efficiency is reduced because a fraction of the steam cycle output is diverted to supply solvent regeneration heat, while additional electrical power is required for auxiliary equipment such as fans, pumps and CO_2 compression. For example, the full-load baseline model in Alruwaili et al. (2025), without lean-vapour compression, shows net efficiency decreasing from 58.70% without CCS to 50.06% with CCS, a reduction of 8.64 percentage points. As a result, net power output is reduced for a given fuel input, and marginal operating costs increase due to higher specific fuel consumption and auxiliary loads.

The combined effect is that NGCC+CCS plants, as conventionally designed, become more constrained precisely as electricity systems transition towards high shares of variable renewable generation. In such systems, plants are required to start more frequently, ramp more steeply and operate at lower part-loads, while CCS integration tends to increase start-up times, reduce net ramping capability and raise the cost of frequent cycling. This tension between system-level flexibility requirements and plant-level CCS constraints provides a central motivation for exploring additional flexibility options, including plant-integrated thermal energy storage and system-level battery storage, which are examined in the following sections.

1.4 System level flexibility requirements in GB

Increasing penetration of variable renewable energy (VRE) changes the operational requirements of the power system. Weather-dependent wind and solar output introduce greater variability and uncertainty in net demand, resulting in more frequent balancing actions, steeper net-load ramps, and extended periods of low system inertia as synchronous thermal plant operates for fewer hours. System operator assessments show that these effects are already evident in current operation, with variable renewables increasingly driving dispatch patterns, reserve requirements and curtailment during periods of network or system constraint (National Grid ESO, 2024).

As a consequence, the system must manage a broader set of flexibility requirements, including frequency response, reserve, reactive-power support and system-security services (NESO, n.d.). These include balancing and reserve capacity to accommodate forecast errors and rapid changes in renewable output; ramping capability to manage sunrise and evening demand transitions as well as large swings in offshore wind generation; and system-strength services such as inertia and fault-level support as conventional synchronous plant runs less frequently (NESO, 2025). The Clean Flexibility Roadmap identifies the need to expand flexibility provision across a wider portfolio of technologies and consumers (DESNZ, 2025a).

Although grid-scale battery storage, interconnection, and demand-side response are expanding rapidly, their contribution is constrained by duration, availability, and economic limits, particularly during extended low-wind conditions. As a result, all credible GB decarbonisation pathways retain a structural role for dispatchable generation capable of providing both energy adequacy and operational flexibility. In this context, gas-fired generation equipped with carbon capture and storage is expected to play a dual role as a low-carbon source of firm capacity and a provider of system-level flexibility. Whether NGCC plants with CCS can credibly fulfil this role without additional flexibility measures is therefore a critical question addressed in the subsequent sections of this thesis.

The National Grid Electricity System Operator became the National Energy System Operator (NESO) in October 2024. References in this thesis retain the organisation name used at publication: National Grid ESO before the transition and NESO thereafter. NESO procures services including frequency response, reserve and stability support. The Clean Power 2030 Action Plan and Clean Flexibility Roadmap describe the expansion of flexibility provision through storage, interconnection, demand-side resources and dispatchable low-carbon generation (DESNZ, 2024, 2025a). The GB flexibility portfolio includes pumped-storage hydropower, battery storage, interconnectors, demand-side response and dispatchable low-carbon generation. These resources contribute over different timescales and under different availability constraints. National system planning therefore considers their combined contribution to balancing electricity supply and demand, including during extended periods of low renewable output (National Grid ESO, 2024; DESNZ, 2024, 2025a).

Energy-storage technologies differ in maturity, discharge duration and round-trip efficiency.

Electricity-storage options range from short-duration batteries to longer-duration mechanical and chemical storage, while TES technologies store energy as heat for later use. Table 1-2 summarises the indicative characteristics relevant to this study.

Table 1-2: Indicative technology-readiness level, duration and round-trip-efficiency ranges for selected storage technologies Compiled from (IRENA, 2020, 2017).

Storage type	Indicative TRL	Typical duration	Indicative RTE	Main role
Pumped-storage hydro	9	4–24 h	70–85%	Multi-hour balancing, stability, black-start
Lithium-ion BESS	9	0.5–4 h	80–90%	Fast frequency response, intraday balancing
Flow batteries	6–8	4–12 h	65–80%	Medium-duration grid support
CAES / LAES	6–8	4–24+ h	50–70%	Bulk long-duration storage
Power-to-hydrogen + reconversion	5–7	Multi-day to seasonal	30–40% (electric-to-electric)	Seasonal storage, cross-sector coupling
TES (sensible heat, heat networks)	8–9	Hours to seasonal	80–95% (on the heat side)	Heat networks, industrial processes
TES (high-temperature latent or thermochemical)	4–7	Hours to days	Configuration-dependent; no single representative RTE stated.	Emerging power/industrial and CCS applications

Source: Compiled from (IRENA, 2020, 2017).

Note: The efficiencies describe different energy-conversion boundaries. Thermal-storage efficiency concerns heat retained and recovered, whereas electrical-storage efficiency concerns electricity supplied and returned. Electrical values may also use different AC or DC boundaries. The entries therefore do not provide a direct efficiency ranking across technologies (IRENA, 2020, Section 2.2, p. 67; IRENA, 2017, p. 37).

Pumped-storage hydropower and other long-duration electricity-storage technologies are relevant to multi-hour balancing, while lithium-ion batteries are widely used for shorter-duration flexibility and fast grid services. Flow batteries provide an emerging medium-duration option. TES differs from these electricity-storage pathways because it stores and returns heat rather than electricity, with sensible-heat systems representing the most mature thermal-storage category (IRENA, 2020, 2017).

1.5 TES as a plant level flexibility option

Thermal energy storage absorbs, stores and subsequently releases heat, allowing heat supply and demand to occur at different times. Figure 1-1 summarises the principal TES categories and their indicative operating-temperature ranges and technology-readiness levels (IRENA, 2020). This study considers TES integrated with the CCS reboiler: heat stored during charging supplies solvent regeneration during discharge, reducing contemporaneous steam extraction from the power cycle.

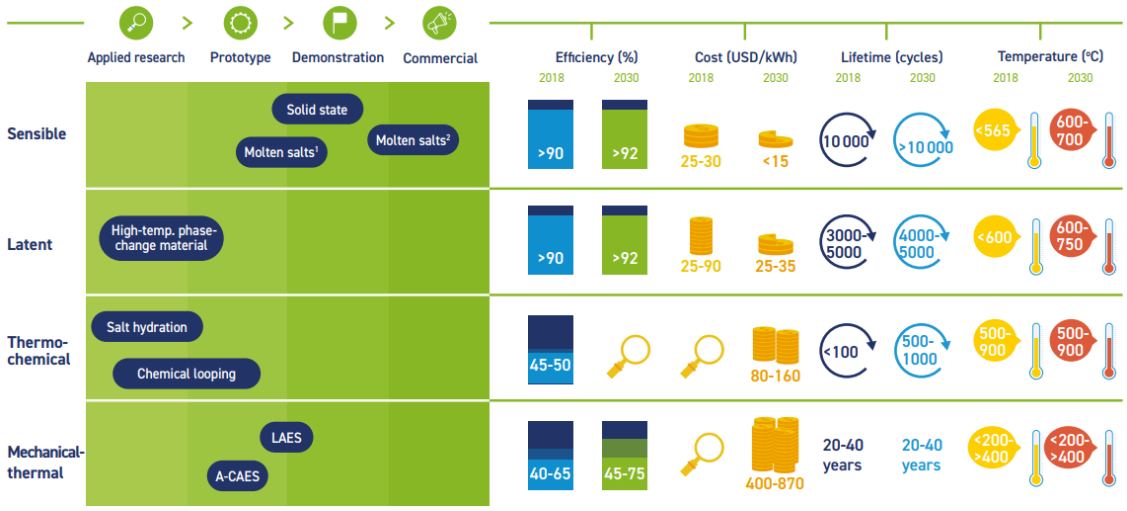


Fig. 1-1: Thermal-energy-storage categories, indicative operating-temperature ranges and technology-readiness levels (IRENA, 2020).

1.5.1 TES technology relevant to NGCC+CCS system

TES technologies are commonly classified as sensible, latent and thermochemical storage. Sensible TES stores heat through a change in the temperature of a liquid or solid medium, while latent TES uses phase change and thermochemical TES relies on reversible reactions or sorption processes. These categories differ in maturity, energy density, cycling behaviour and integration complexity (IRENA, 2020).

The reference capture conditions are taken from Alruwaili et al. (2025), whose model uses 30 wt% aqueous monoethanolamine, a 90% CO_2 capture rate and a stripper pressure of 1.62 bar. The reboiler operates at 117.5°C. Steam is extracted from the intermediate-pressure/low-pressure turbine crossover at 510 kPa and reduced to 250 kPa, corresponding to a saturated-steam temperature of 127.4°C. These conditions define the reference heat-delivery duty. The TES calculation assumes useful heat can be supplied at suitable temperature and pressure, but does not simulate storage temperature or pressure evolution. Steam accumulators and pressurised hot-water stores are conceptual integration options requiring further engineering assessment.

The value of the TES pathway arises from timing. During selected lower-price periods, thermal energy is charged into the store. During selected higher-price periods, useful stored heat replaces part of the contemporaneous reboiler steam extraction. This allows additional electrical output to be retained from the NGCC steam cycle while maintaining the underlying solvent-regeneration duty. The mechanism is therefore reboiler-side thermal decoupling rather than electrical-energy storage.

The wider sensible-heat TES literature remains relevant for contextual and cost-plausibility purposes, but the technologies must not be conflated. Commercial two-tank molten-salt systems generally operate at substantially higher temperatures and are established mainly in

concentrating-solar-power applications. Solid-media sensible-heat systems also cover broader temperature ranges. These systems can inform the plausible installed-cost envelope for sensible-heat storage, but they are not treated as direct representations of the reboiler-grade steam-side store modelled in this thesis.

Published work has examined steam-accumulator integration as a route to improving the flexibility of power plants with post-combustion CO_2 capture (Skjervold and Nord, 2024). However, no built and vendor-costed multi-hour NGCC+CCS TES retrofit is used as the basis of the present study. The selected technology family is therefore retained as an engineering concept for screening analysis rather than as a vendor-specific design.

1.5.2 Technical requirements favouring sensible TES for NGCC+CCS

The reboiler-side retrofit context imposes technical requirements that favour a sensible-heat steam-side storage concept over less mature or less directly compatible alternatives. The principal requirements are set out below:

Temperature compatibility: TES must supply useful heat at conditions suitable for the reference CCS reboiler described in Section 1.5.1. Establishing the storage operating range requires selection of the storage medium, pressure levels and heat-exchanger arrangement.

Reboiler-side integration: The store must deliver useful heat to the CCS solvent-regeneration reboiler without routing stored heat through the turbine. Electrical-equivalent flexibility arises only because useful discharge reduces contemporaneous steam extraction. The TES concept must therefore be evaluated as a thermal subsystem integrated with the steam-side CCS heat pathway.

Multi-hour cycling duty: The application requires repeated charging and discharging over intra-day periods. Sensible-heat storage is retained because it offers a comparatively mature and scalable route for repeated thermal cycling. The detailed vessel arrangement, pressure management, thermal losses and auxiliary requirements remain engineering design questions outside the reduced-order model.

Retrofit feasibility: A practical retrofit must account for available space, vessel configuration, piping, pressure control, heat exchangers, auxiliary equipment and constructability around the existing NGCC+CCS plant. These requirements are site-specific and cannot be inferred solely from generic TES technology data.

Installed-cost uncertainty: No vendor-certified installed cost is available for a built multi-hour NGCC+CCS steam-side TES retrofit. The study therefore uses a transparent engineering anchor and a sensitivity envelope informed by analogous sensible-heat TES evidence. Molten-salt, solid-media and institutional TES cost sources are used as analogue evidence only, not as direct quotations for the proposed reboiler-grade store (Glatzmaier, 2011; IEA Energy Storage TCP, 2024; Jacob et al., 2017; Pompei et al., 2023).

Table 1-3 distinguishes the selected technology family from the principal alternatives and clarifies how each is used in this research.

Table 1-3: Simplified comparison of TES technology families relevant to reboiler-side CCS heat shifting.

TES technology family	Indicative temperature context	Relevant strength	Key limitation for this study	Role in the thesis	Treatment
Steam accumulator / pressurised hot-water storage	Reference heat-delivery conditions in Section 1.5.1; storage operating range not simulated	Potential for buffering heat supply within the steam-side reboiler system	Requires assessment of vessel design, pressure levels, heat exchangers, auxiliaries and retrofit integration	Conceptual options for reboiler-side heat storage	Heat-storage operation modelled; detailed vessel design not simulated
Two-tank molten-salt sensible TES	Typically associated with substantially higher-temperature applications	Commercially established at utility scale in concentrating-solar-power applications	Operating range and integration architecture are not direct representations of the reboiler-grade duty	Analogue and contextual cost evidence only	Not modelled as the proposed TES technology
Solid-media sensible TES	Broad temperature range depending on storage medium and thermal interface	Potentially low-cost sensible-heat storage with scalable media options	Thermal-interface design and suitability for the reboiler-side duty require separate engineering assessment	Analogue and contextual cost evidence only	Not modelled directly
Latent-heat TES	Application-dependent phase-change temperature	Higher energy density and near-constant-temperature heat release may be attractive in some applications	Material stability, containment and scale-up remain application-specific	Excluded from the modelled pathway	Outside scope
Thermochemical TES	Application-dependent reaction or sorption temperature	Potentially high energy density and long-duration storage	Greater process complexity and lower maturity for the repeated reboiler-side cycling duty considered here	Excluded from the modelled pathway	Outside scope

Source: Author's synthesis based on the TES technology literature and verified analogue evidence (Glatzmaier, 2011; IRENA, 2020; Jacob et al., 2017; Pompei et al., 2023; Skjervold and Nord, 2024). *Higher-temperature sensible-heat systems are included as analogue or contextual evidence only.*

These requirements justify the selection of a reboiler-grade sensible-heat steam-side storage concept for the techno-economic screening analysis. The detailed engineering design and vendor-specific installed cost remain outside the scope of the thesis.

The literature indicates that sensible TES can support more flexible operation of NGCC plants with post-combustion CCS by shifting regeneration-heat demand across time. Its value is influenced by storage cost, integration design and electricity-price volatility, rather than by thermal efficiency alone (Limb et al., 2022). However, the evidence base remains limited for GB-specific assessments that compare plant-integrated TES with external grid-scale BESS using a common flexibility-cost metric. This gap motivates the comparative framework developed in this thesis. Section 2.4 reviews the steam-accumulator study by Skjervold and Nord (2024), and Section 2.6 explains how the present research differs.

1.6 BESS as a system-level comparator

Grid-scale lithium-ion BESS is considered as an external electrical-storage comparator for plant-integrated TES. The comparison examines the cost of flexibility supplied at the grid interface alongside the cost of shifting heat supply within the NGCC+CCS plant.

1.6.1 BESS architecture and grid integration

A BESS stores electrical energy electrochemically and returns it through a grid-connected power-conversion system. Utility-scale installations typically comprise battery modules, a Battery Management System (BMS), bidirectional Power Conversion System (PCS), supervisory controls and grid-interconnection equipment including Energy Management System (EMS). Within this thesis, lithium-ion BESS is used as the external electrical-storage comparator.

A grid-connected BESS absorbs and exports electricity through a bidirectional converter, with its usable output governed by converter rating, available state of charge and operating strategy. Figure 1-2 presents the principal components of a grid-connected BESS and identifies the grid-interface boundary used to distinguish BESS from plant-integrated TES.

BESS offers system-level operational advantages in renewable-heavy power systems by providing fast, controllable electrical response at the grid interface. Grid-forming inverters enable BESS to provide synthetic inertia and fast frequency response, which are critical for maintaining grid stability as renewable energy penetration increases (Cao et al., 2024).

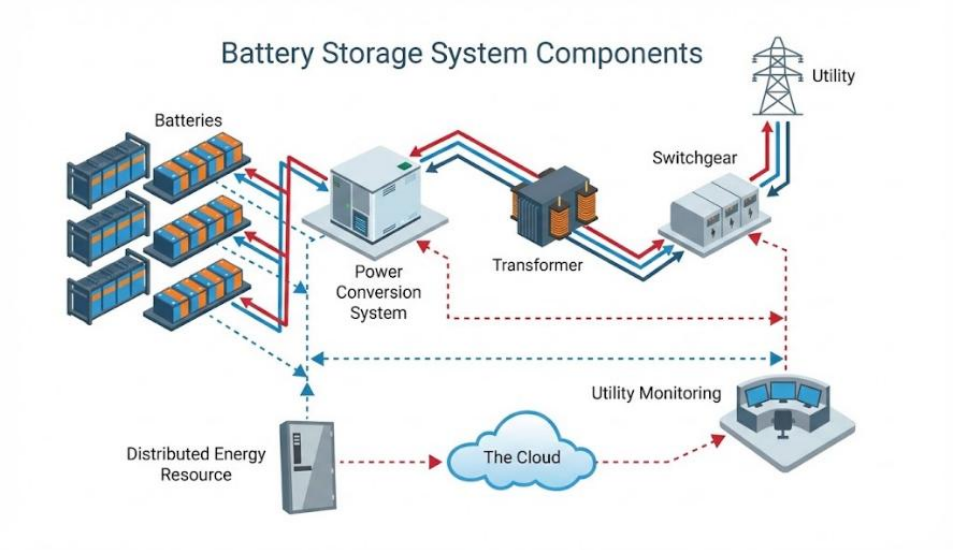


Fig. 1-2: Main components and grid integration of a BESS, showing battery modules, power conversion system, transformer, switchgear, and utility interface (Kozich, 2024)

1.6.2 BESS deployment in GB

GB has emerged as one of the leading markets for grid-scale BESS deployment, driven by the increasing need for flexibility and fast-response services in a power system with declining inertia. The introduction of the Dynamic Containment service in 2020 marked a structural shift in GB frequency control, creating market opportunities for assets capable of sub-second response. The Clean Power 2030 Action Plan also identifies 23–27 GW of battery capacity by 2030 as part of GB's future flexibility portfolio (DESNZ, 2024).

Operational experience from GB power system modelling indicates that BESS are frequently deployed for multiple services, with revenues derived from stacking opportunities across Dynamic Containment, balancing mechanism participation, and limited wholesale energy arbitrage (Guerra et al., 2024). However, BESS capacity factors remain relatively low, at approximately 3–5% in the modelled 2030 and 2040 scenarios, reflecting their primary role in short-duration balancing rather than sustained energy shifting (Guerra et al., 2024).

Figure 1-3 places current and pipeline UK BESS capacity against the 2030 national target, illustrating the scale of expected BESS deployment while reinforcing its role as a grid-side flexibility comparator in this research.

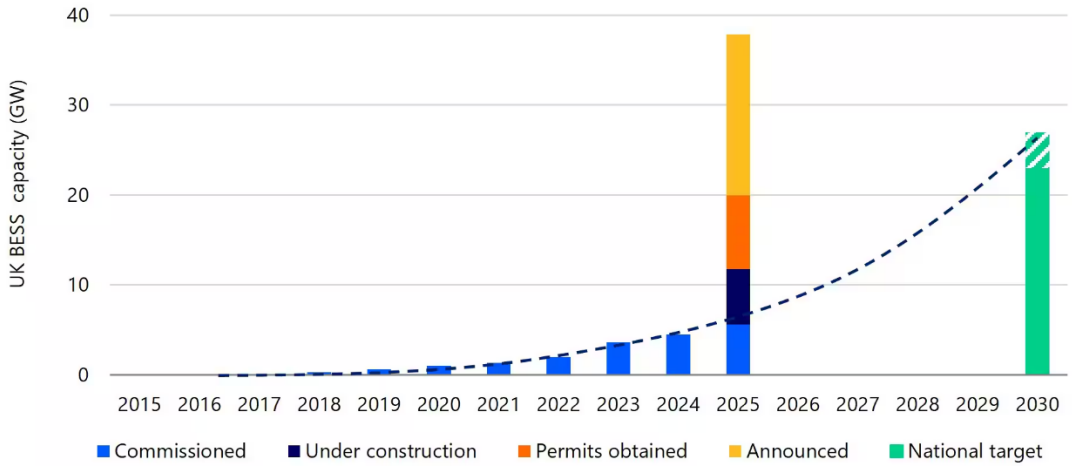


Fig. 1-3: UK Cumulative commissioned BESS capacity, the project pipeline, and the 2030 national target (Hutters, 2025)

Source: Hutters (2025), based on BloombergNEF, the European Energy Storage Inventory, the Clean Power 2030 Action Plan and RaboResearch analysis.

This study examines plant-integrated TES and grid-scale BESS as distinct flexibility pathways. TES shifts heat supply to the CCS reboiler, while BESS stores and exports electricity at the grid interface. Their costs are compared under explicitly stated operating and accounting assumptions, without assuming equivalent services.

1.7 Research gap

The literature reviewed in Sections 1.2–1.6 establishes that post-combustion CCS introduces a structural heat–power coupling within NGCC plants. Solvent regeneration requires a sustained reboiler heat supply, normally provided through steam extraction from the steam cycle. This reduces net electrical output and creates an operational constraint when NGCC+CCS plants are required to respond flexibly to increasingly variable electricity-system conditions (Cheng et al., 2023; Rúa et al., 2020).

Plant-integrated TES shifts the timing of heat supplied to the CCS solvent-regeneration reboiler. It is considered alongside other approaches to flexible capture operation, including solvent storage and alternative heat-supply arrangements (Limb et al., 2022).

This study examines the marginal cost of reboiler-side TES and grid-side BESS within a GB-focused screening analysis. Its focus is the application of chronological storage constraints to CCS reboiler heat shifting and the comparison of the resulting electrical-equivalent flexibility cost with selected BESS configurations. The analysis examines how operating assumptions, storage duration and economic parameters affect that comparison and the TES installed-cost thresholds for parity.

1.8 Aim, research questions and objectives

Research Aim:

The aim of this research is to evaluate the electrical-equivalent flexibility and associated cost of plant-integrated thermal energy storage supplying the CCS reboiler, and to compare these estimates with selected grid-scale lithium-ion battery storage cases in a Great Britain screening study. The analysis examines the influence of operating rules, storage capacity and economic assumptions within the physical and accounting boundaries of each pathway.

Research Questions:

1. How much CCS reboiler heat can TES shift under the adopted price-based operating rules and storage constraints, and what electrical-equivalent flexibility does this represent?
2. What annual AC electrical output and marginal cost of flexibility arise from the selected BESS configurations, and how do the results differ under a supplementary SOC-constrained, price-responsive operating case?
3. How do the TES and BESS marginal-cost estimates compare under their stated accounting boundaries, and how do storage duration, operating assumptions and economic parameters affect the comparison and TES installed-cost parity thresholds?
4. How should differences in physical function, dispatch and model limitations shape the interpretation of the TES–BESS cost comparison?

Research Objectives:

1. To establish the no-storage NGCC+CCS reference case, the hourly price and thermal-load evidence, and the physical and temporal boundaries of the screening analysis.
2. To apply a chronological SOC-constrained TES model that distinguishes requested and accepted charging, charging spill, useful reboiler discharge and unmet TES discharge requests, while accounting for storage losses, capacity limits and cyclic annual energy balance.
3. To evaluate annual AC electrical output and marginal cost of flexibility for the 100 MWh and 200 MWh BESS configurations, each with a 50 MW converter, using their operating schedules and stated financial assumptions.
4. To assess both BESS sizes through a supplementary SOC-constrained, price-responsive sensitivity with explicitly defined operating constraints, replacement assumptions and accounting boundaries.
5. To calculate TES and BESS marginal costs using defined annual costs and flexibility outputs. TES costs include annualised capital cost, fixed operating cost, charging opportunity cost and useful-discharge electricity value. Each BESS calculation applies its stated cost and revenue treatment.

6. To examine sensitivity to TES duration, dispatch thresholds, thermal-load profile and selected technical and economic assumptions, considering storage durations from 1 to 72 hours with a four-hour reference case.
7. To identify TES installed-cost parity thresholds against the selected BESS comparators and assess the implications of differences in operational capability and plant-integration requirements for interpreting the cost comparison.

1.9 Scope and boundaries

The study compares plant-integrated TES supplying the CCS solvent-regeneration reboiler with grid-scale lithium-ion BESS operating at the electrical interface. It evaluates the marginal cost of flexibility within the stated plant and storage boundaries.

The TES pathway represents sensible-heat storage supplying the CCS reboiler. Charging diverts steam-cycle thermal energy into storage, while useful discharge replaces contemporaneous steam extraction and provides an electrical-equivalent flexibility credit. Heat delivery is assumed to meet the reference reboiler temperature and pressure requirements. Storage temperature and pressure evolution, vessel selection, heat-exchanger design, auxiliary equipment and retrofit constructability are outside the model. The credited electrical output remains conditional on plant integration and available electrical headroom.

The study does not model high-temperature molten-salt storage as the proposed plant-integrated technology. Molten-salt and other sensible-heat storage systems are relevant only as analogue evidence when assessing the plausibility of the TES installed-cost range. Latent storage, thermochemical storage, cold TES, grid-scale TES, capture-rate modulation, solvent storage, power-augmentation TES and seasonal thermal storage are outside the modelled pathway.

The geographical scope of the modelling is Great Britain (GB), comprising England, Scotland and Wales. This boundary follows the GB wholesale-price data and battery-revenue benchmark used in the analysis. The United Kingdom (UK) also includes Northern Ireland. References to UK policy or statistics retain their stated geographical coverage; publication by a UK government body does not itself establish that a source covers the whole UK.

Existing HOMER simulations provide the no-storage NGCC+CCS reference case and the operating records for the 100 MWh and 200 MWh BESS configurations, each with a 50 MW converter. TES is evaluated through a chronological hourly SOC-constrained calculation using the reference price and reboiler-load series. The TES reference uses a four-hour vessel and p40/p60 dispatch thresholds. A supplementary SOC-constrained, price-responsive sensitivity considers both BESS sizes under separately stated operating and accounting assumptions.

The economic assessment uses an 8% real discount rate and a 25-year horizon. TES annual net cost includes annualised capital cost, fixed operating cost and accepted-charging opportunity cost, less the electricity value associated with useful discharge. Headline BESS costs use reconstructed incremental cash flows, external fixed operating cost and the

benchmark-based non-wholesale revenue adjustment. The supplementary BESS sensitivity uses its separate battery-only cost and energy-revenue boundary. Marginal costs are calculated using TES electrical-equivalent flexibility and BESS AC electrical output, respectively.

The central TES installed-cost assumption is £40/kWh-th, with £25–£60/kWh-th examined in sensitivity analysis. This is a screening assumption for installed storage cost, rather than a supplier quotation for a specified NGCC+CCS retrofit. Installed-cost parity analysis examines its effect on the comparison with the selected BESS cases.

Several issues remain outside scope: dynamic solvent-regeneration and steam-cycle simulation; plant start-up, ramp-rate and minimum-stable-load modelling; detailed BESS market co-optimisation and electrochemical degradation modelling; CO_2 transport-and-storage tariffs; carbon-price exposure; tax and financing structures; transmission-network constraints; nodal pricing; lifecycle assessment; and critical-mineral quantification. These exclusions preserve a focused screening comparison of reboiler-side TES and grid-side BESS around a common NGCC+CCS reference case.

1.10 Novel contributions and thesis structure

This section summarises the original contributions of the research and outlines the structure of the thesis.

1.10.1 Novel contributions

The study makes three principal contributions to the analysis of flexibility provision for NGCC plants equipped with post-combustion CCS.

Application of chronological TES screening to CCS reboiler heat shifting: The study applies the established storage-balance formulation described by Brown et al. (2018) to reboiler-side heat shifting. The application combines price-based operating rules, reboiler-linked heat requests and finite storage capacity to estimate useful heat discharge and its electrical-equivalent flexibility cost.

Installed-cost sensitivity and parity analysis: The study examines how the assumed TES installed cost affects its marginal cost of flexibility and its comparison with the selected BESS cases. The analysis considers cost sensitivity and identifies the installed-cost thresholds at which the pathways reach parity under the stated operating and accounting assumptions.

Comparison of storage costs under explicit operating and accounting assumptions: The study evaluates TES and selected BESS configurations using defined annual costs and flexibility outputs. It examines the effects of operating and economic assumptions, including a separate SOC-constrained BESS sensitivity, and identifies the boundaries governing interpretation of the comparison.

PlantFlex Lab is a development-stage companion demonstrator for preliminary scenario exploration. Its scope and development status are described in Appendix G.

1.10.2 Thesis structure

The remainder of the thesis is organised as follows:

- Chapter 2 reviews the literature on NGCC plants with CCS and flexibility challenges, TES technologies, BESS and their system-level role, and GB power-system characteristics that shape flexibility needs.
- Chapter 3 describes the methodological framework, including conceptual plant-level models for NGCC+CCS with plant-integrated TES and NGCC+CCS supported by grid-scale BESS, key assumptions, boundaries, and evaluation metrics.
- Chapter 4 presents the results of the techno-economic analysis under GB-focused scenarios, comparing flexibility performance and marginal flexibility costs for the two architectures.
- Chapter 5 concludes the thesis by answering the research questions, identifying the main limitations, outlining future research directions and summarising the contribution of the study.

2. LITERATURE REVIEW

This chapter reviews the literature relevant to flexibility provision for NGCC plants equipped with post-combustion CCS. It first establishes the baseline performance, cost characteristics and operating assumptions of NGCC+CCS systems, then examines the thermal and operational constraints introduced by solvent regeneration. The review subsequently evaluates plant-level flexibility measures, with particular attention to plant-integrated TES, before assessing grid-scale BESS as an external system-level flexibility resource. The chapter concludes by identifying the gap addressed in this thesis: the absence of a consistent GB-focused framework for comparing plant-side thermal flexibility and grid-side electrical storage using a common marginal-cost metric.

2.1 NGCC with CCS: performance and cost characteristics

This section establishes a baseline representation of NGCC power plants equipped with post-combustion CCS, as they are treated in the literature under steady or quasi-steady operation. The purpose is to define a reference NGCC+CCS plant in terms of configuration, thermodynamic performance, cost structure, and operating assumptions before any flexibility considerations are introduced. By clearly defining this baseline, subsequent sections and the later techno-economic comparison can attribute changes in performance, cost, and system value explicitly to flexible operation and additional flexibility mechanisms, rather than to ambiguity in initial assumptions.

2.1.1 Baseline NGCC+CCS configuration and system boundaries

The NGCC+CCS literature adopts a largely consistent reference configuration and system boundary for techno-economic and operational analysis, which is also adopted in this thesis as the baseline case. In this baseline arrangement, a conventional NGCC plant comprising a gas turbine (GT), heat recovery steam generator (HRSG), and steam turbine (ST) is integrated with a post-combustion CO_2 capture unit located downstream of the HRSG (Alruwaili et al., 2025; Hughes et al., 2023).

Post-combustion chemical absorption using Monoethanolamine (MEA) is the dominant capture technology assumed for NGCC applications. In this configuration, CO_2 is absorbed from the flue gas in an absorber column and subsequently released in a stripper through solvent regeneration. The regeneration heat demand is supplied by steam extracted from the low-pressure section of the steam turbine, establishing a direct thermodynamic coupling between electricity generation and capture operation (Alruwaili et al., 2025). The separated CO_2 stream is then compressed for transport and storage.

Across the literature, system boundaries typically encompass the full NGCC power block, the capture plant, and the CO_2 compression system. Integrated modelling frameworks explicitly represent steam extraction, auxiliary power consumption, and compression loads within the same boundary, allowing NGCC+CCS plants to be treated as a single generation asset in

comparative assessments (Alruwaili et al., 2025; Cheng et al., 2023). Despite differences in modelling detail and enhancement options, studies converge on this reference architecture, providing a stable baseline against which operational constraints and flexibility measures are evaluated. Figure 2-1 illustrates this reference NGCC+CCS configuration and shows the steam-extraction pathway that links solvent regeneration to the power cycle.

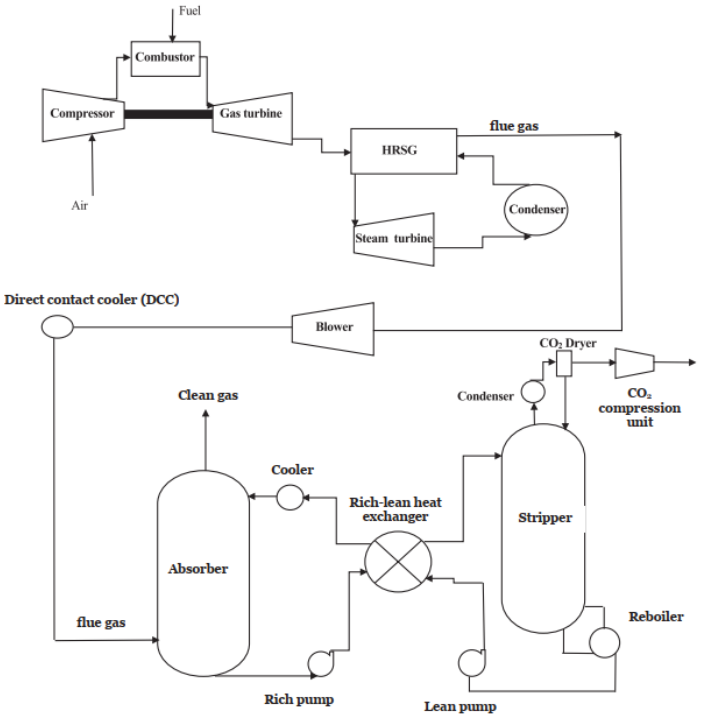


Fig. 2-1: NGCC plant with post-combustion CO_2 capture, showing the GT–HRSG–ST arrangement and solvent-regeneration steam extraction (Alruwaili et al., 2025).

2.1.2 Technology maturity and readiness of NGCC+CCS

The treatment of NGCC+CCS as a baseline technology presupposes a sufficient level of technological maturity. Technology Readiness Levels (TRLs) are commonly used in the literature to assess whether a technology is suitable for deployment-oriented analysis rather than speculative evaluation.

Post-combustion CO_2 capture using chemical absorption is widely classified as a high-TRL technology (TRL 8–9) for power-sector applications. Core components such as absorbers, strippers, solvent circulation systems, and CO_2 compressors have been demonstrated at pilot, demonstration, and early commercial scales. In contrast, flexibility-enhancing add-ons such as advanced solvents or integrated storage concepts are typically assigned lower TRLs.

Wang et al. (2024) review established and emerging CO_2 capture, transport, storage and utilisation technologies across different technology-readiness levels. Figure 2-2 summarises this wider technology context. The maturity of individual components should be distinguished from the performance and integration requirements of a complete NGCC+CCS installation.

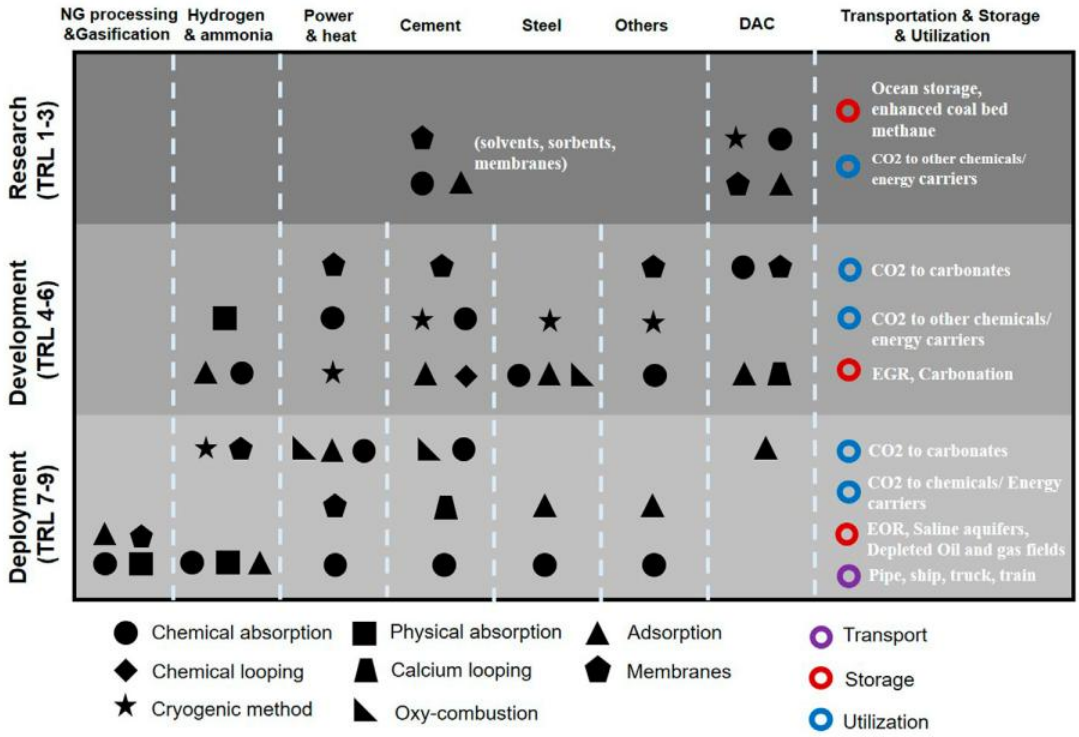


Fig. 2-2: Indicative technology-readiness levels for CO_2 capture, transport, storage and utilisation technologies (Wang et al., 2024).

2.1.3 Thermodynamic performance impacts of CCS integration

Integrating post-combustion CCS into an NGCC plant reduces net electrical efficiency and increases heat rate. The magnitude depends on the reference plant, capture configuration, operating conditions and auxiliary requirements. Efficiency penalties are therefore reported here for specific study configurations rather than as a single universal range.

The primary source of this penalty is steam extraction for solvent regeneration, which reduces mass flow through the low-pressure steam turbine and directly lowers net power output. Secondary losses arise from auxiliary electricity consumption, including solvent circulation, cooling systems, and CO_2 compression. While process modifications can marginally reduce these impacts, the underlying thermodynamic penalty remains intrinsic to post-combustion capture.

Alruwaili et al. (2025, Tables 5–6) report net efficiencies of 58.70% without CCS and 50.06% with CCS for their full-load baseline configuration without lean-vapour compression. The corresponding reduction is 8.64 percentage points. Kamolov et al. (2024, abstract and Table 7) report a decrease from 55.8% to approximately 46.8% for their final capture configuration, equivalent to approximately 9 percentage points. These results illustrate the efficiency cost of capture in two different plant configurations; they do not establish a universal penalty for NGCC+CCS.

These results establish efficiency degradation as a structural characteristic of NGCC+CCS systems, rather than a modelling artefact, and motivate later analysis of flexibility strategies that seek to manage, rather than eliminate this penalty. Table 2-1 summarises representative reported efficiency penalties for NGCC plants with post-combustion CCS and shows the range of thermodynamic impacts used to frame the later flexibility analysis.

Table 2-1: Reported thermodynamic performance of NGCC plants with and without post-combustion CCS.

Study	Configuration	Net efficiency without CCS (%)	Net efficiency with CCS (%)	Efficiency penalty (percentage points)
Alruwaili et al. (2025)	Full-load NGCC baseline with MEA capture, without lean-vapour compression	58.70	50.06	8.64
Kamolov et al. (2024)	Final NGCC capture configuration with 40% MEA and 45% exhaust-gas recirculation	55.8	≈46.8	≈9.0

Note: Efficiencies are reported on each source's stated basis. Percentage-point reductions compare the paired without-CCS and with-CCS efficiencies within each study. The configurations differ, so the values are illustrative examples rather than a common performance assumption for this thesis.

2.1.4 Steady-state capture and cost assumptions

Alruwaili et al. (2025) model an NGCC plant with a specified CO_2 capture fraction of 90%. This source-specific assumption provides the capture basis for the reference configuration used in this thesis. The capture fraction describes the proportion of incoming CO_2 removed by the capture process; it does not specify a constant reboiler heat demand.

A fixed capture fraction can coexist with changing regeneration-heat requirements as plant load and the quantity of CO_2 processed vary. In this thesis, reboiler heat demand is represented by a prescribed hourly, load-dependent profile rather than a dynamic capture-process simulation. TES shifts the timing of steam-side heat extraction while supplying part of that prescribed reboiler demand during discharge. Chapter 3 defines the thermal-load profile and storage calculation.

Under steady-state operation, the cost structure of NGCC plants equipped with post-combustion CCS is dominated by high CCS-related capital investment and operating costs driven by efficiency losses. Across the literature, the capture plant consistently represents the largest source of incremental cost relative to an unabated NGCC plant.

A defining feature of this cost structure is its sensitivity to utilisation. High fixed CCS capital costs must be recovered over generated electricity, while fuel and auxiliary costs remain elevated due to the CCS energy penalty. Consequently, the cost per unit of electricity increases sharply as capacity factor declines, making NGCC+CCS economics strongly dependent on

sustained utilisation even before flexible operation is considered (Hersbach et al., 2025). These cost considerations make utilisation and operating conditions important when assessing NGCC+CCS performance. Table 2-2 summarises the dominant cost components under steady NGCC+CCS operation and identifies the main drivers that become important when utilisation and flexibility are considered.

Table 2-2: Dominant cost components of NGCC+CCS under steady operation based on Rahmanta et al. (2025) and Alruwaili et al. (2025).

Cost category	Dominant components	Key driver
Incremental CAPEX	Absorber & stripper columns; solvent systems; heat exchangers	Capture plant scale
Additional CAPEX	CO_2 compression and dehydration	Compression pressure & flow
Fuel OPEX	Increased gas consumption	Reduced net efficiency and increased fuel consumption per MWh
Auxiliary OPEX	Solvent pumps, cooling systems, CO_2 compression	Reboiler duty & compression load
Cost sensitivity	Capacity factor dependence	High fixed CCS capital

2.1.5 Typical utilisation assumptions and their limitations

Utilisation affects the economics of NGCC plants with CCS because capital and fixed operating costs must be recovered over the electricity generated and CO_2 captured. Hersbach et al. (2025) note that CCS assessments often assume capacity factors of 80% or higher, while lower utilisation increases the cost of CO_2 avoidance under their model assumptions.

Their analysis varies average lifetime capacity factor for an NGCC retrofit and examines US financial support, including 45Q tax credits and assumed savings from avoided California cap-and-trade obligations. It does not predict hourly plant dispatch. The resulting economic thresholds therefore depend on the study's capital costs, operating costs and policy assumptions.

Hersbach et al. (2025) separately examine upstream methane leakage, which is not captured by the power-plant CCS system. Their emissions findings depend on methane leakage, CO_2 capture fraction and the time horizon used to assess methane's warming effect. Reduced utilisation and upstream methane leakage are consequently distinct considerations: the former affects fixed-cost recovery, while the latter limits the emissions reduction achievable through point-source capture. Table 2-3 summarises these distinctions.

Table 2-3: Utilisation, financial and emissions considerations in the NGCC+CCS assessment by Hersbach et al. (2025).

Aspect	Treatment in Hersbach et al. (2025)	Implication for this thesis	Location in Hersbach et al. (2025)
Operating profile	Average lifetime capacity factor is varied; hourly dispatch is not predicted.	The study provides utilisation-cost context rather than an hourly operating schedule.	Section 2.2
Cost allocation	Fixed costs are recovered over capacity-factor-dependent quantities of captured CO_2.	Lower utilisation can increase unit costs under the specified cost assumptions.	Sections 2.2 and 3.2
Financial support	US 45Q credits and assumed California cap-and-trade savings affect economic viability.	Reported economic thresholds are specific to the financial scenario.	Sections 2.2 and 4.1
Emissions boundary	Upstream methane leakage remains outside point-source CO_2 capture.	Capture percentage alone does not establish total greenhouse-gas reduction.	Sections 2.1 and 3.1

2.2 NGCC+CCS flexibility and operational constraints

Throughout the literature on low-carbon power generation, the term flexibility is used to describe a range of operational capabilities, including rapid ramping, sustained part-load operation, cycling tolerance, and the ability to respond to short-term system imbalances. In the context of NGCC plants equipped with post-combustion CO_2 capture, however, flexibility cannot be assessed solely in terms of electrical output variation, as capture performance and thermal integration introduce additional constraints that directly affect operating cost and efficiency.

In this chapter, flexibility is therefore considered as the ability of NGCC+CCS plants to vary net electrical output in response to system conditions without disproportionate increases in marginal cost or degradation of capture integrity. This definition explicitly recognises that flexible operation in CCS-equipped plants is governed not only by turbine and generator dynamics, but also by the availability of low-grade heat for solvent regeneration, the resulting efficiency penalties at part-load operation, and the cost implications of frequent cycling or ramping. Framing flexibility in this manner provides a consistent basis for evaluating alternative flexibility pathways, including plant-integrated TES and externally provided system-level flexibility, which are examined in the subsequent sections of this chapter.

Increasing variable renewable generation creates a need to examine NGCC+CCS operation across different utilisation levels and operating conditions. Steam extraction for solvent regeneration couples the capture process to electrical generation, making integrated plant behaviour relevant to flexibility assessment (Rúa et al., 2020). Lower utilisation also increases the fixed cost recovered per unit of output, while upstream methane leakage remains a separate influence on the overall emissions benefit of CCS (Hersbach et al., 2025).

Post-combustion CCS requires heat for solvent regeneration, normally supplied through steam extraction from the power cycle. This creates a thermodynamic coupling between capture operation and electrical output (Alruwaili et al., 2025). The response to changing load depends on the integrated plant configuration and controls; a steady-state reference alone does not establish its dynamic operating limits. Figure 2-3 illustrates the steam-extraction pathway linking solvent regeneration to the power cycle.

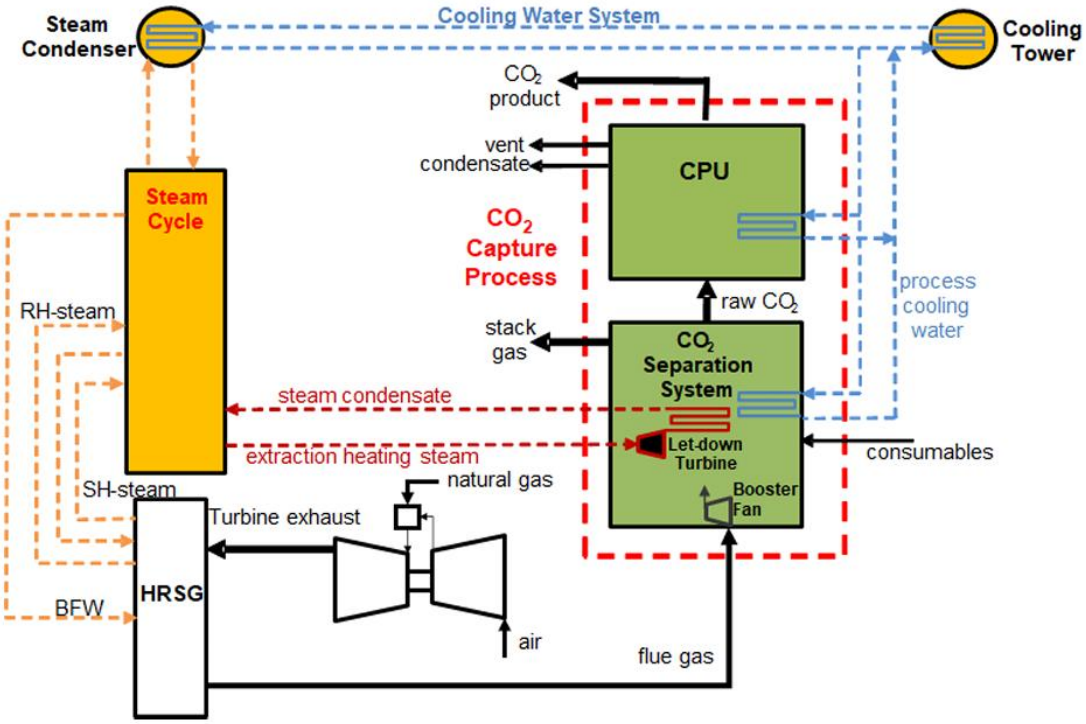


Fig. 2-3: NGCC with post-combustion CO_2 capture, showing low-pressure steam extraction for solvent regeneration and the resulting heat–power coupling (Hughes et al., 2023).

At reduced loads, solvent-based CCS amplifies efficiency degradation compared with unabated NGCC operation. Process studies show that:

- Rising specific reboiler duty: As plant load decreases, solvent regeneration demands a higher specific heat input, amplifying efficiency penalties at part load (Alruwaili et al., 2025).
- Increased steam diversion from the power cycle: Greater steam extraction at low load reduces net electrical output and increases fuel consumption per unit of electricity generated (Alruwaili et al., 2025).
- Elevated minimum stable generation: Solvent circulation, thermal stability, and capture-efficiency requirements impose a lower bound on achievable turndown (Alruwaili et al., 2025; Kamolov et al., 2024).

- Degraded economic performance under cycling: Frequent part-load operation erodes the economic viability of NGCC+CCS compared with steady baseload operation (Kamolov et al., 2024).

These effects transform CCS from a relatively steady efficiency penalty at baseload into a mechanism that amplifies inefficiency and constrains turndown during flexible operation.

Capture-rate modulation and temporary bypass offer a different flexibility mechanism from thermal storage. Reducing capture duty can release energy for electricity generation, but it also reduces the amount of CO_2 captured during that period. This trade-off must be distinguished from shifting the timing of regeneration-heat supply while retaining the underlying capture duty. Section 2.3 discusses these alternative mechanisms.

Lower utilisation can increase the unit cost of CCS because capital and fixed operating costs are recovered over smaller quantities of captured CO_2. Hersbach et al. (2025) demonstrate this sensitivity for their NGCC retrofit and financial assumptions. Their analysis provides context for examining utilisation and cost recovery, while the hourly TES–BESS comparison in this thesis addresses a different question: the cost of credited flexible electricity under specified operating schedules.

2.3 Plant-level flexibility options for NGCC+CCS

This section reviews plant-level measures proposed to improve the operational flexibility of NGCC plants with post-combustion CCS. The options include solvent storage, capture-rate modulation, steam bypass and alternative heat-supply arrangements, and process-level modifications intended to reduce the capture-energy penalty. Their operating mechanisms and limitations are examined to establish why plant-integrated TES is considered as a distinct flexibility pathway in Section 2.4.

2.3.1 Solvent storage and flexible regeneration concepts

Among plant-level flexibility measures proposed for NGCC plants with post-combustion CCS, solvent storage is the most extensively analysed option in the literature. The concept introduces intermediate storage of CO_2-rich solvent within the absorber–stripper loop, enabling limited temporal separation between CO_2 absorption and solvent regeneration without altering the underlying chemical capture process.

In conventional operation, solvent circulates between absorption and regeneration, with regeneration requiring heat from the steam cycle. Rich-solvent storage introduces an intermediate inventory so that some regeneration can be deferred while absorption continues. The potential reduction in contemporaneous steam extraction depends on available solvent-storage capacity and the ability to regenerate the accumulated solvent later. Solvent storage therefore shifts regeneration activity, whereas the TES pathway examined in this thesis stores heat for later delivery to the reboiler.

2.3.2 Capture-rate modulation and bypass strategies

In contrast to solvent storage, a second class of plant-level flexibility measures seeks to improve NGCC+CCS dispatchability by modulating the CO_2 capture rate, including partial capture operation or temporary bypass of the capture plant. By reducing steam extraction for solvent regeneration, these strategies increase net electrical output during periods of high electricity demand.

The attraction of capture-rate modulation depends on the value of additional electricity relative to the consequences of reduced capture. A higher electricity price may favour additional generation, while emissions limits and the cost of uncaptured CO_2 constrain that choice. These considerations distinguish capture-rate modulation from the TES mechanism adopted here, which retains the prescribed reboiler duty and changes when part of its heat supply is extracted from the steam cycle.

However, these benefits are achieved through a direct trade-off between electrical flexibility and emissions performance. Reducing the capture rate increases uncaptured CO_2 emissions during periods of high output and lowers aggregate capture effectiveness, which can significantly erode the net climate benefit of CCS, particularly at low-capacity factors with increased cycling.

Capture-rate modulation provides short-term operational relief by increasing dispatchability but does so by compromising emissions integrity rather than addressing the underlying heat–power coupling of post-combustion capture. Unlike solvent storage, which preserves capture effectiveness while shifting regeneration timing, capture-rate modulation transfers the flexibility burden to emissions performance and therefore represents an operational workaround rather than a robust solution compatible with stringent decarbonisation pathways.

2.3.3 Steam bypass and alternative heat-supply concepts

A third class of plant-level flexibility measures seeks to mitigate the impact of CCS heat demand on net power output by modifying how solvent regeneration heat is supplied, rather than altering capture rate or introducing solvent storage. These approaches include steam bypass arrangements and auxiliary heat-supply concepts intended to preserve electrical output during periods of high demand.

Cheng et al. (2023) examine a distinct heat-integration approach combining an NGCC plant, post-combustion capture and modular direct air capture (DAC). Their post-combustion capture unit follows NGCC load, while low-pressure steam allocation to DAC regeneration can vary independently. This allows operation to shift between additional electricity generation and additional atmospheric CO_2 removal. The study therefore provides evidence for flexible DAC heat integration, rather than rich-solvent storage or bypass of the post-combustion capture unit.

Alternative heat-supply arrangements must be evaluated within their own energy and emissions boundaries. Protecting electrical output by changing the source of regeneration heat does not remove the heat requirement itself; any additional fuel, electricity or recovered-heat use must

be included in the assessment. The present thesis instead considers temporal storage of steam-cycle heat for subsequent delivery to the CCS reboiler.

From a process perspective, reviews of post-combustion chemical absorption systems emphasise that solvent regeneration requires sustained thermal input irrespective of the heat source employed. Practical implementation of steam bypass or auxiliary heat-supply concepts is further constrained by integration complexity, heat-transfer limitations and site-specific feasibility, particularly in retrofit applications (Akinmoladun and Tomomewo, 2025).

Importantly, these approaches do not provide temporal energy shifting. Unlike solvent storage, which defers regeneration in time, steam bypass and alternative heat-supply concepts maintain continuous regeneration while attempting to protect electrical output. Consequently, they address the symptom of power loss rather than the structural heat–power coupling inherent to post-combustion CCS, limiting their effectiveness as standalone flexibility solutions in power systems characterised by frequent cycling and volatile dispatch.

2.3.4 Process-level modifications to reduce energy penalty

Process-level modifications aim to reduce the energy penalty of post-combustion CCS by improving capture-plant efficiency through enhanced heat integration, configuration changes, and related process optimisations, without altering the capture architecture or operating schedule. Table 2-4 summarises how process-level modifications affect NGCC+CCS performance and shows why efficiency improvement alone does not provide temporal flexibility.

Table 2-4: Impact of process-level modifications on NGCC+CCS performance.

Aspect	Baseline NGCC+CCS	Process-optimised NGCC+CCS	Interpretation
Reboiler heat demand	🔴 High	🟢 Lower ↓	Energy penalty reduced
Auxiliary power consumption	🔴 Higher	🟢 Lower ↓	Improved net output
Net electrical efficiency	🔴 Lower	🟢 Improved ↑	Efficiency gain
Part-load performance	🔴 Degraded	🟢 Improved ↑	Reduced penalty at part load
Capture architecture	○ Fixed	○ Fixed	No structural change
Temporal flexibility	🔴 None	🔴 None	No time-shifting capability
Heat–power coupling	🔴 Strong	🔴 Strong	Coupling remains

Legend: 🟢 improvement 🔴 adverse / unchanged ↑ increase ↓ decrease ○ no structural change

Source: Author's synthesis based on Akinmoladun and Tomomewo (2025) and Alruwaili et al. (2025).

As summarised in above, process-level modifications reduce the energy penalty per unit of CO_2 captured and improve net efficiency under design and part-load conditions, but leave the capture configuration and requirement for continuous thermal input unchanged (Akinmoladun and Tomomewo, 2025; Alruwaili et al., 2025). They should therefore be viewed as

complementary efficiency improvements rather than standalone flexibility solutions, because they do not provide temporal shifting of regeneration demand or resolve the structural heat–power coupling identified in Sections 2.2 and 2.3.

The plant-level flexibility measures reviewed in Sections 2.3.1–2.3.4—solvent storage, capture-rate modulation, steam bypass and alternative heat-supply concepts, and process-level efficiency modifications—provide varying degrees of operational relief but retain important limitations. Solvent storage enables short-duration thermal shifting; capture-rate modulation improves dispatchability at the expense of emissions integrity; steam bypass and auxiliary heat supply reallocate energy flows without temporal decoupling; and process-level modifications reduce the energy penalty while leaving the underlying thermal coupling in place.

These limitations motivate consideration of plant-integrated TES as a distinct flexibility pathway. TES is examined in the following section as a means of shifting regeneration-heat supply across time without relying on capture-rate reduction or bypass.

2.4 TES integration in NGCC+CCS plants: retrofit context

Plant-integrated TES provides a means of shifting solvent-regeneration heat supply across time without relying on capture-rate reduction or bypass. Thermal energy can be stored during lower-value operating periods and discharged during selected higher-value periods so that part of the CCS reboiler duty is supplied without contemporaneous steam extraction from the NGCC steam cycle.

Skjervold and Nord (2024) modelled a 598 MW coal-fired power plant with solid-sorbent CO_2 capture and a 600 m³ steam accumulator. They examined stored-steam discharge for sorbent regeneration and feedwater heating. Their results included an electrical-output increase of 66.9 MW lasting approximately 3.2 minutes; this interval should be distinguished from the complete discharge sequences, which lasted approximately 31–38 minutes (Skjervold and Nord, 2024).

The study demonstrates the steam-extraction heat-shifting principle for its particular plant and capture configuration. Its conclusions identify techno-economic evaluation and comparison with batteries as future work. The present thesis instead examines annual hourly operation and flexibility costs for a reboiler-side TES pathway associated with NGCC and amine-based CCS, alongside selected grid-scale BESS cases.

2.4.1 Operating modes of retrofitted NGCC+CCS plants with TES

In conventional NGCC+CCS operation, the solvent-regeneration reboiler is supplied through steam extraction from the steam cycle, creating a direct coupling between capture operation and net electrical output. A TES-integrated configuration introduces an intermediate thermal store on the reboiler-side heat-supply pathway. The gas turbine and capture chemistry remain unchanged, while the timing of steam extraction and reboiler heat supply is partly decoupled.

The concept can be described through three operating modes: charging, neutral operation and discharging. During charging, additional steam-side thermal energy is directed into the store

during lower-value periods. During neutral operation, the reboiler is supplied conventionally from the steam cycle. During discharging, useful stored heat supplies part of the reboiler duty, reducing contemporaneous steam extraction. Table 2-5 summarises these modes.

Table 2-5: TES-enabled operating modes for reboiler-side thermal shifting.

Operating mode	Reboiler-side heat pathway	Net electrical effect	Capture treatment	System function
Charging	Steam-side thermal energy directed into TES	Temporary output penalty relative to neutral operation	Underlying solvent-regeneration duty retained	Store thermal energy during lower-value periods
Neutral	Steam cycle supplies the reboiler directly	Baseline output	Conventional capture operation	Operate without thermal shifting
Discharging	TES supplies useful heat to the reboiler	Electrical output retained through reduced contemporaneous steam extraction	Underlying solvent-regeneration duty retained	Recover plant-side flexibility during selected higher-value periods

Source: Author's synthesis based on (Limb et al., 2022).

TES changes the timing of the reboiler heat supply rather than the underlying solvent-regeneration requirement. Its usefulness is therefore constrained by the available charging opportunities, the rate at which thermal energy can be stored and released, the usable vessel capacity and the chronological sequence of lower- and higher-value periods. These factors motivate the hourly state-of-charge formulation adopted in Chapter 3.

The operating-mode description is conceptual. It does not imply that every charging opportunity can be accepted or that every requested discharge can be delivered. Finite-vessel saturation, stored-energy availability and thermal losses must be represented explicitly when calculating deliverable MWh-flex.

2.4.2 Techno-economic implications of TES retrofitting

Retrofitting sensible-heat TES to an NGCC plant with post-combustion CCS increases capital expenditure but changes the temporal profile of steam-side energy use within the plant. TES does not remove the intrinsic heat requirement of solvent regeneration and does not improve intrinsic cycle efficiency automatically. Its economic value arises from shifting part of the reboiler heat supply away from selected higher-price periods.

The additional installed cost is influenced by the storage vessel, pressure regime, heat exchangers, piping, auxiliaries, balance-of-plant modifications and retrofit constructability. For a reboiler-grade steam accumulator or pressurised hot-water store, these costs remain site-specific. No built and vendor-costed multi-hour NGCC+CCS TES retrofit is used as a direct cost basis in this study. The later techno-economic analysis therefore treats TES capex as a transparent engineering anchor within a sensitivity envelope rather than as a measured market price.

Figure 2-4 reproduces the comparison in Limb et al. (2022, Figure 5), based on New York Independent System Operator (NYISO) nodal electricity prices and the NETL B31B NGCC reference plant with CANSOLV capture. The results show 30-year net present value differences between TES configurations and a no-TES reference, expressed in millions of 2018 US dollars. Positive differences indicate an improvement relative to that reference, rather than necessarily a positive overall project NPV. The figure illustrates the influence of market conditions and plant configuration on TES value; this thesis instead evaluates MCF for its specified GB price series and plant assumptions.

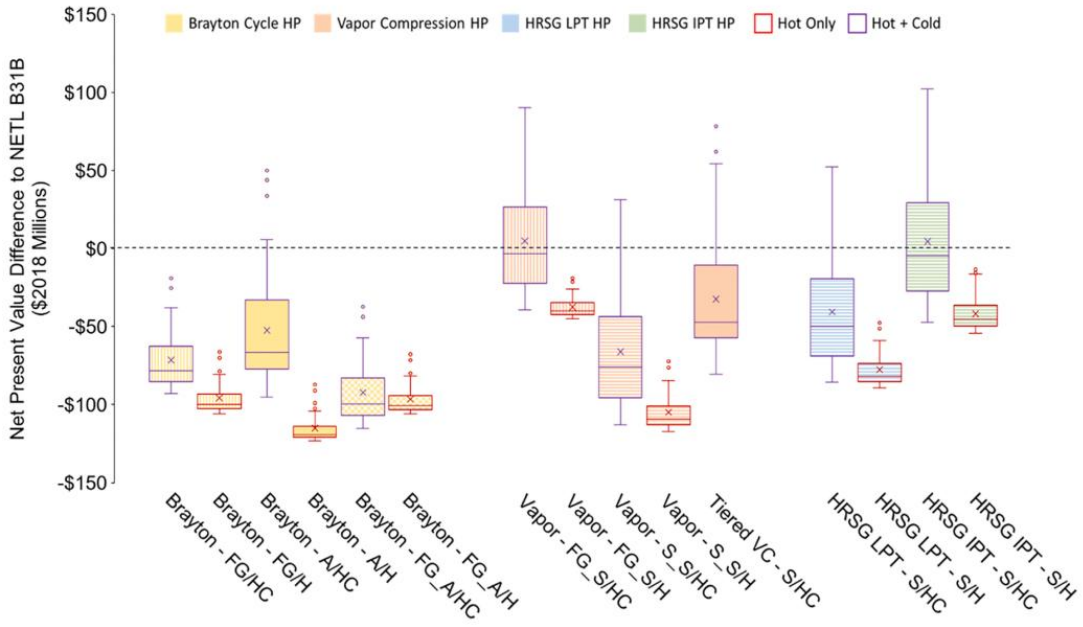


Fig. 2-4: Thirty-year NPV comparison of TES configurations for the NETL B31B NGCC–CCS plant using NYISO electricity prices (Limb et al., 2022).

The techno-economic performance of the TES pathway is therefore governed by:

- The magnitude and frequency of electricity-price spreads;
- The duration and rate capability of the thermal store;
- The chronological availability of acceptable charging and discharging windows;
- The installed cost and site-specific integration requirements; and
- The electrical-equivalent output retained when contemporaneous reboiler steam extraction is reduced.

The analysis examines how TES installed cost and operating assumptions affect its cost relative to the selected BESS cases. The installed-cost parity analysis in Chapters 3 and 4 identifies the TES cost thresholds at which the pathways have equal MCF under the specified assumptions.

2.4.3 TES comparison boundary and integration limitations

Plant-integrated TES and grid-scale electrical storage deliver flexibility at different system boundaries. TES acts within the NGCC+CCS plant by shifting reboiler heat supply across time. During useful discharge, stored heat replaces part of the contemporaneous steam extraction and allows additional electrical output to be retained while the solvent-regeneration duty remains supplied.

Grid-scale BESS operates outside the plant process by absorbing and exporting electricity at the grid interface. It can provide electrical services that are outside the TES boundary, including fast-response and wider market-facing services. Conversely, it does not alter the CCS reboiler heat demand or the internal steam-cycle coupling.

The comparison uses annual incremental net cost per credited MWh-flex. Chapter 3 specifies the output definitions, dispatch assumptions and cost components for each pathway.

Plant-integrated TES remains a targeted and context-dependent flexibility option. Its effectiveness is limited first by finite vessel capacity and chronology. A thermal store can accept only a bounded quantity of heat and can discharge only the energy available within the vessel. Closely clustered charging opportunities can therefore create spill, while insufficient stored energy can limit useful discharge during later higher-value periods.

Storage duration is also important. Increasing vessel size can recover additional useful heat-shifting opportunities, but it also increases installed capacity and cost. Larger thermal stores are not automatically more cost-effective on a £/MWh-flex basis. The practical value of a given duration must be evaluated against the operating evidence and the intended reboiler-side duty.

Retrofit feasibility and installed cost remain uncertain. A steam accumulator or pressurised hot-water concept requires site-specific pressure matching, heat exchangers, piping, auxiliaries, spatial integration and constructability assessment. Analogue sensible-heat TES evidence can inform a plausible cost envelope, but it does not provide a vendor-certified price for a built NGCC+CCS retrofit.

TES also introduces thermal losses and does not remove the total solvent-regeneration requirement. It reallocates heat supply across time. The pathway therefore complements rather than replaces wider system-level flexibility resources such as BESS, interconnection and demand response.

These limitations support a bounded screening interpretation: TES may address the CCS reboiler-side coupling efficiently under suitable cost and operating conditions, but its competitiveness depends on vessel design, chronology, installed cost and site-specific integration.

2.5 BESS as a system-level flexibility resource

This section reviews BESS as an external system-level flexibility resource and establishes the basis for its use as the comparator to plant-integrated TES. It examines the role of BESS in

power-system flexibility and low-inertia operation, the grid services it can provide, its sizing and siting constraints, its techno-economic characteristics and its position within the future GB electricity system. The section then clarifies how grid-scale BESS is positioned relative to plant-integrated TES within the marginal-cost comparison developed in this thesis.

2.5.1 Role of BESS in power-system flexibility

BESS are widely characterised in the literature as grid-connected, system-level flexibility resources, deployed to support power-system operation under increasing penetration of variable renewable energy. Unlike plant-integrated flexibility options such as TES in NGCC+CCS plants, BESS operates independently of individual generators and provides flexibility directly to the electricity network.

Comprehensive reviews emphasise that the primary value of BESS lies in its ability to deliver fast, controllable electrical power, rather than large-scale energy shifting (Chatzigeorgiou et al., 2024). This reflects the intrinsic characteristics of electrochemical storage, including high ramp rates, modular deployment, and electrical rather than thermal coupling to the system. Consequently, BESS is predominantly used to address system-level flexibility requirements, such as short-term balancing, congestion management, frequency support, and mitigation of renewable variability.

From a system-boundary perspective, this role is distinct from plant-level flexibility measures: TES integrated within NGCC+CCS plants targets internal process constraints, specifically the coupling between steam extraction and solvent regeneration, whereas battery storage does not alter generator operation or internal energy flows but injects or absorbs power at grid connection points, with its value determined by network conditions and market signals rather than plant thermodynamics.

Studies of future power-system evolution in GB consistently show that BESS deployment is closely linked to increasing shares of wind and solar generation (Cao et al., 2024). In this context, batteries are not positioned as substitutes for firm thermal generation, but as complementary system assets that enable higher renewable penetration while maintaining operational security.

For the purposes of this thesis, BESS is treated as an external flexibility procurement pathway, distinct from plant-integrated TES. The analysis therefore compares internal flexibility delivered within NGCC+CCS plants against external flexibility supplied by the power system via BESS, rather than comparing storage technologies in isolation.

2.5.2 Role of BESS in low-inertia power systems

Increasing penetration of converter-interfaced renewable generation has led to a systematic reduction in synchronous inertia, fundamentally altering frequency dynamics in modern power systems. Under low-inertia conditions, frequency deviations occur more rapidly following

disturbances, increasing the rate of change of frequency (RoCoF) and reducing the response time available to conventional, governor-based generators.

The literature reviewed in this thesis consistently shows that, as system inertia declines, frequency stability becomes dominated by response speed rather than response magnitude (Alsharif et al., 2023). In such systems, traditional primary frequency response is often too slow to arrest frequency excursions before critical thresholds are reached, creating a structural need for fast-acting flexibility resources.

BESS are widely identified as well suited to this role due to their power-electronic interfaces and decoupling from mechanical inertia. Unlike synchronous generators, BESS can deliver rapid, bidirectional active-power response based solely on electrical measurements, enabling effective mitigation of high RoCoF and deep frequency nadirs across a wide range of operating conditions (Alsharif et al., 2023).

Evidence from renewable-dominated and weak networks further reinforces this role. Sakib et al. (2025) show that, in systems with high wind penetration and limited synchronous generation, BESS significantly improves frequency stability margins and reduces reliance on curtailment or must-run thermal units, even when storage duration is limited.

The dominant frequency-related challenges associated with low-inertia operation, and the corresponding contributions of BESS, are summarised in Table 2-6. Collectively, the literature positions BESS as a stability-oriented flexibility resource whose primary value lies in mitigating fast frequency phenomena, rather than providing sustained energy balancing, in contrast to plant-integrated TES, which addresses internal thermal constraints rather than system-wide frequency dynamics.

Table 2-6: Frequency stability challenges in low-inertia power systems and corresponding BESS support functions.

Low-inertia challenge	System-level impact	BESS contribution
High rate of change of frequency (RoCoF)	Increased risk of protection trips and generator disconnection	Rapid active-power injection enabled by power-electronic interfaces
Deep frequency nadir following disturbances	Elevated risk of under-frequency load shedding	Arresting frequency decline through fast frequency response
Reduced response time of conventional generators	Insufficient primary frequency response	Sub-second controllable power response independent of mechanical inertia
Weak or renewable-dominated networks	Coupled voltage–frequency instability	Coordinated active and reactive power control

Source: Author's synthesis based on (Alsharif et al., 2023; Sakib et al., 2025).

2.5.3 Grid services provided by BESS

The rapid-response characteristics discussed in Section 2.5.2 allow BESS to participate in several grid-service markets. These services differ in response timescale, duration and revenue structure, with frequency-related products forming an important part of the GB battery market.

In the GB context, this capability is formalised through Dynamic Containment, where BESS provides proportional active-power response outside a defined frequency deadband. Studies demonstrate that service performance is governed primarily by power capacity and control speed, rather than energy duration, reinforcing the interpretation of BESS as a stability-driven asset (Chatzigeorgiou et al., 2024; Fan et al., 2025).

Voltage regulation and network support: Beyond frequency response, BESS can contribute to voltage regulation and local network support, particularly in weak or renewable-dominated networks. The literature indicates that fast, localised reactive-power control from batteries can improve voltage profiles and reduce reliance on network reinforcement, with effectiveness strongly dependent on connection location and network topology (Khosravani et al., 2025; Sakib et al., 2025). In most markets these services are secondary deployment drivers compared with frequency response, where frequency-related revenues dominate.

Grid-scale BESS can earn revenue from wholesale trading, frequency response, reserve, Balancing Mechanism participation and capacity-related payments. Access to these revenue streams depends on state of charge, availability and operational commitments (Jennings, 2025b). Figure 2-5 illustrates monthly variation in GB benchmark revenues across market streams between November 2024 and November 2025.

The headline BESS calculation retains wholesale trading cash flows from the specified simulations performed using HOMER Pro and applies a separate non-wholesale revenue adjustment. This adjustment uses the non-wholesale components of Modo Energy's 2024 revenue databook, with monthly annualised rates weighted by calendar days (Jennings, 2025a). Wholesale revenue is excluded from the adjustment to avoid double counting. The adjustment is held fixed in the revised sensitivity and uncertainty analysis. Figure 2-5 provides market context; its later reporting period is not the basis of the adjustment.

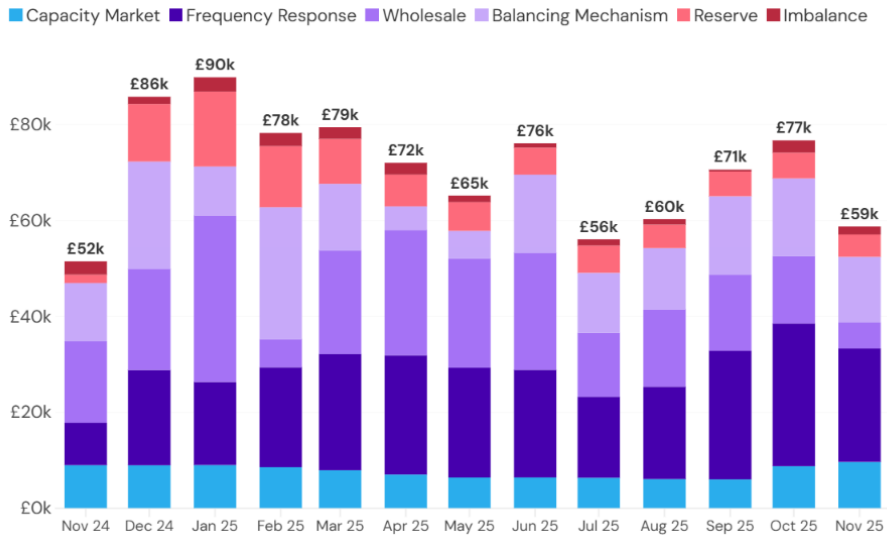


Fig. 2-5: Monthly GB BESS benchmark revenues by market stream, November 2024 to November 2025 (Modo Energy).

Source: Reproduced from (Jennings, 2025b), published by Modo Energy.

Table 2-7 summarises the principal BESS revenue streams and distinguishes wholesale trading from the non-wholesale adjustment used in this study.

Table 2-7**:** Key BESS revenue streams relevant to GB grid-scale battery operation.

Revenue stream	Role in BESS operation	Relevance
Frequency response / dynamic response	Fast injection or absorption of power to support system frequency.	Included within the aggregated non-wholesale revenue adjustment; service delivery is not separately simulated.
Reserve services	Availability to increase export or reduce import when the system requires additional balancing support.	Included within the aggregated non-wholesale revenue adjustment; availability commitments are not separately simulated.
Balancing Mechanism participation	Post-gate actions instructed by the system operator to balance supply and demand.	Included within the aggregated non-wholesale revenue adjustment; individual balancing actions are not separately simulated.
Wholesale arbitrage	Charging during lower-price periods and discharging during higher-price periods.	Wholesale trading cash flows from the specified HOMER Pro simulations are retained in the cost calculation and excluded from the external revenue adjustment.
Capacity-related revenue	Payment for reliable capacity availability during system stress periods.	Included within the aggregated non-wholesale revenue adjustment; capacity obligations are not separately simulated.

Source: Author's synthesis based on (Chatzigeorgiou et al., 2024; Fan et al., 2025; Jennings, 2026, 2025b)

2.5.4 Sizing, siting, and operational constraints of BESS

BESS sizing involves separate choices of power rating and energy capacity. Power rating limits instantaneous charging and discharging, while energy capacity and the permitted state-of-charge range constrain the energy available for delivery. Energy capacity divided by power rating defines nominal storage duration; usable discharge duration also depends on operating conditions and conversion losses. Zhang et al. (2024) consider power rating, energy capacity and connection location jointly when sizing BESS for frequency and voltage support.

State-of-charge management affects service availability. Cao et al. (2024) examine Dynamic Containment in Great Britain and show that the configuration of SOC management influences frequency-response performance, stored-energy availability and battery degradation. Rapid response capability therefore needs to be considered alongside the energy required to sustain a service and restore SOC.

Connection location and control strategy also influence the contribution of BESS to network support. Zhang et al. (2024) incorporate frequency and voltage control into their sizing and siting analysis, illustrating the importance of the intended service and network conditions. In this thesis, the selected 100 MWh and 200 MWh cases share a 50 MW converter rating. These are study configurations, rather than universal limits on battery duration or suitability.

2.5.5 Techno-economic characteristics of BESS

BESS capital cost includes components associated with power rating and energy capacity. Zhang et al. (2024) represent these separately in their investment-cost formulation. Increasing energy capacity at a fixed power rating increases nominal duration and the energy-related investment, but its effect on cost per delivered MWh also depends on utilisation, dispatch and lifetime costs.

Operating strategy influences both energy delivery and battery wear. Cao et al. (2024) demonstrate the interaction between SOC management, service performance and degradation in frequency-response operation. Economic assessment therefore requires an explicit treatment of cycling, replacement and conversion losses, alongside capital and operating expenditure.

The headline BESS assessment in this thesis retains the selected HOMER operating schedules and reconstructs replacement and salvage cash flows on the adopted financial basis. It includes external fixed O&M and a separate non-wholesale revenue adjustment. The supplementary SOC-constrained sensitivity uses a different dispatch and cost boundary, which is specified separately in Chapter 3. The resulting MCF values describe these defined cases rather than an intrinsic cost advantage or disadvantage of battery storage.

2.5.6 BESS in GB and its relationship to plant-integrated TES

The Clean Power 2030 Action Plan identifies a GB battery-capacity range of 23–27 GW for 2030 within a wider portfolio that includes long-duration storage, interconnection, consumer-led flexibility and dispatchable generation (DESNZ, 2024, Table 1). This positions batteries as one contributor to electricity-system flexibility alongside resources with different operating characteristics.

BESS can participate in energy trading and grid services, subject to stored-energy availability, connection limits and operational commitments. Section 2.5.3 reviews these revenue streams and explains their treatment in this study. Here, BESS is evaluated as a grid-side electrical-storage pathway, while TES shifts heat supply within the CCS reboiler system. The comparison below distinguishes their physical functions and establishes the basis for comparing flexibility costs. Plant-integrated TES and grid-scale BESS provide flexibility through different physical mechanisms and at different system boundaries. This study compares their costs per credited MWh-flex while retaining those distinctions; it does not assume that the two pathways provide equivalent services.

Grid-scale BESS operates at the electrical interface. It absorbs and exports electricity through a converter and can provide fast-response, balancing and wider market-facing services (Cao et al., 2024; Chatzigeorgiou et al., 2024; Sakib et al., 2025; Zhang et al., 2024). Its value depends on electrical-storage sizing, converter rating, state-of-charge management, degradation, market conditions and network context. BESS does not alter the solvent-regeneration heat demand or the steam-extraction coupling inside an NGCC+CCS plant.

Plant-integrated TES acts within the NGCC+CCS asset. For the pathway examined in this thesis, useful heat discharged from TES supplies the CCS solvent-regeneration reboiler. Useful TES discharge reduces contemporaneous steam extraction and allows additional electrical output to be retained from the steam cycle. TES therefore targets the internal heat-power coupling introduced by post-combustion CCS rather than providing a generic substitute for all grid-side BESS services (Limb et al., 2022).

Table 2-8 summarises the physical and operational distinctions between the pathways. Their costs are expressed in the common unit £/MWh-flex, with credited electricity calculated separately for TES and BESS using the definitions in Chapter 3.

Table 2-8: Conceptual comparison of plant-integrated TES and grid-scale BESS as flexibility pathways.

Dimension	BESS	Plant-Integrated TES
System boundary	Grid-level resource providing external flexibility to the power system	Plant-level modification embedded within the NGCC+CCS generating asset
Energy domain	Electrical energy shifting through charge–discharge cycles	Thermal (process) energy shifting for solvent regeneration
Flexibility character	Short-duration, market-driven flexibility (frequency response, balancing services)	Process-coupled flexibility aligned with continuous CCS heat demand
Primary constraint addressed	System-wide variability and stability requirements	Heat–power coupling introduced by post-combustion CCS
Dependence on external systems	Value depends on electricity prices, market access, network conditions and operating constraints.	Value depends on electricity prices, plant operating conditions and integration with the steam cycle and CCS reboiler.

Source: Author's synthesis based on (Cao et al., 2024; Chatzigeorgiou et al., 2024; Limb et al., 2022; Sakib et al., 2025; Zhang et al., 2024).

2.6 Comparative gaps and research positioning

The contribution relative to Skjervold and Nord (2024) lies in the application and analysis rather than a new heat-shifting mechanism. Their study examines short-duration steam-accumulator operation in a coal-fired plant with solid-sorbent capture. This thesis applies hourly storage constraints and prescribed price-based dispatch to NGCC+CCS reboiler heat shifting over a year, calculates the associated flexibility cost, and compares it with selected BESS cases. These differences extend the economic and comparative questions while retaining distinct plant, capture and storage assumptions.

This section synthesises the literature on plant-level thermal flexibility and grid-scale electrical storage to establish the scope, comparison basis and economic questions addressed by this study.

2.6.1 Flexibility constraints in NGCC-CCS systems

Flexibility limitations in NGCC plants equipped with post-combustion CO_2 capture arise from the thermal coupling between electricity generation and solvent regeneration requirements. While NGCC plants without CCS are valued for their rapid ramping capability and high part-load efficiency, the addition of post-combustion capture fundamentally alters this behaviour by imposing substantial parasitic heat loads and tighter operating constraints (Limb et al., 2022).

In their introductory discussion, Limb et al. (2022, p. 2) state that supplying solvent-regeneration heat through steam extraction can reduce total electrical generation by approximately 12%. This estimate provides literature context for the electrical-output penalty associated with steam extraction. This steam extraction, typically from the crossover between the intermediate- and low-pressure steam turbines, creates a structural dependency between heat supply and capture performance (Rúa et al., 2020). At reduced electrical output, the availability of low-grade steam diminishes, forcing operational trade-offs between capture rate, efficiency penalties, and auxiliary energy consumption (Limb et al., 2022).

Thermal storage is one approach investigated for separating the timing of regeneration-heat supply from electricity generation (Limb et al., 2022). This thesis examines steam-side heat storage supplying the CCS reboiler during discharge. The resulting electrical benefit arises from reduced contemporaneous steam extraction; heat-pump operation is not represented in the model.

Hersbach et al. (2025, Section 4.1) find that CCS adds costs below a capacity factor of 61.8% under their assumed US 45Q incentives and California cap-and-trade savings. This is a scenario-specific economic threshold, rather than a general operating limit for NGCC+CCS. Its relevance here is the sensitivity of fixed-cost recovery to utilisation; the threshold is not transferred to the GB flexibility-cost calculation.

The coupling between steam extraction and solvent regeneration provides the physical basis for examining reboiler-side TES (Rúa et al., 2020). Grid-scale BESS provides flexibility through electrical charging and discharging at the grid interface. The comparison therefore evaluates the costs of these distinct pathways under their specified operating and accounting assumptions.

2.6.2 Research gap and thesis scope

This study examines the cost of reboiler-side thermal energy storage and grid-side battery storage within a GB-focused screening analysis. Its contribution lies in applying chronological storage constraints to CCS reboiler heat shifting and comparing the resulting electrical-equivalent flexibility cost with selected BESS configurations.

The TES calculation represents charging and discharging chronologically, subject to thermal-rate limits, finite storage capacity, conversion losses and cyclic annual state-of-charge closure. It distinguishes requested charging from accepted charging and useful discharge from unmet

discharge requests. The BESS assessment uses the operating records of the selected 100 MWh and 200 MWh configurations, supplemented by a separate SOC-constrained, price-responsive sensitivity.

MCF is defined here as average incremental net cost per credited MWh-flex. TES costs include charging opportunity cost and useful-discharge electricity value. Headline BESS costs use reconstructed incremental cash flows, external fixed operating costs and a benchmark-based non-wholesale revenue adjustment. The supplementary BESS sensitivity applies its separate operating and accounting assumptions. Chapter 3 defines these calculations and their boundaries.

This metric differs from conventional levelised cost of storage because it deducts specified electricity value or revenue. LCOS and annualised capacity cost describe costs relative to energy output and capacity, respectively (Schmidt et al., 2019). Marginal reserve prices concern the cost of supplying additional reserve, rather than average annual cost per credited energy unit (Hummon et al., 2013, pp. 11, 21). Investment measures such as net present value, internal rate of return and payback address profitability; Vannoni and Sorce (2025, p. 6) apply such measures in a comparison involving turbine inlet cooling, a different thermal-storage application from the CCS reboiler pathway examined here.

The analysis examines how storage duration, operating assumptions and economic parameters affect the cost comparison and TES installed-cost parity thresholds. The common energy-based denominator supports comparison of the specified cases while their physical functions, dispatch and accounting boundaries determine how the results can be interpreted.

3. METHODOLOGY

This chapter sets out the methodological framework used to compare plant-integrated TES and grid-scale BESS as flexibility pathways for an NGCC plant with post-combustion CCS. The analysis is based on a common no-storage reference case and evaluates each storage pathway using a consistent marginal flexibility-cost metric, expressed as GBP/MWh-flex.

The modelling approach combines HOMER Pro and Python because the two flexibility pathways are represented differently. HOMER Pro is used to simulate the no-storage baseline and the BESS cases, while Python is used for post-processing and for the reduced-order TES calculation. This distinction is central to the methodology because BESS is represented as an electrical storage component in HOMER Pro, whereas TES is evaluated externally as a reboiler-side heat-shifting proxy.

3.1 Modelling

The modelling stage establishes the computational workflow used to convert the input data and case definitions into comparable flexibility-cost outputs. The workflow links three tasks: construction of the HOMER Pro baseline and BESS cases, external Python calculation of the TES reboiler heat-shifting proxy, and post-processing of each pathway into a common marginal cost of flexibility metric.

Figure 3-1 shows the sequence of model inputs, simulation stages, post-processing calculations and internal consistency checks used in the study.

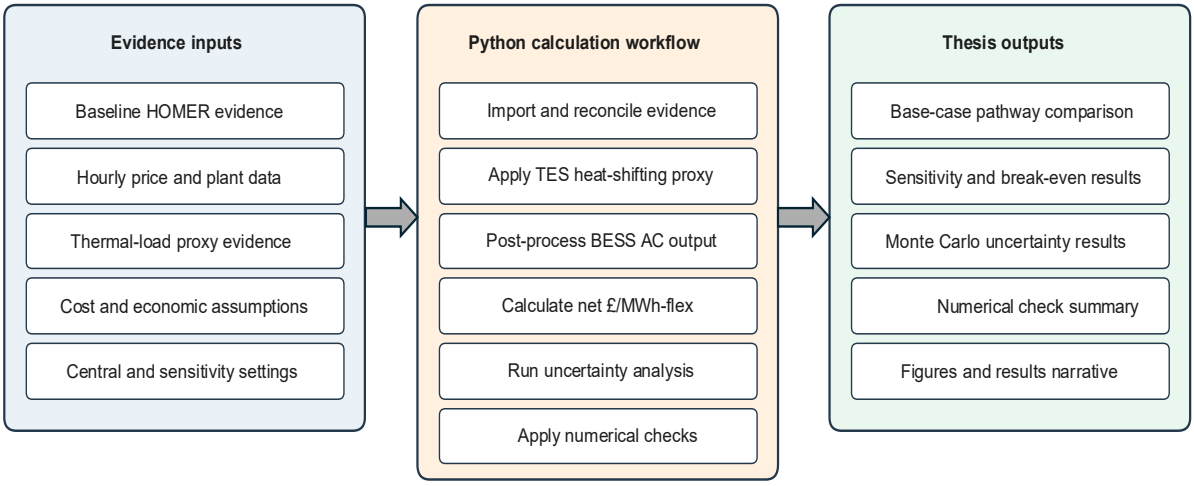


Fig. 3-1: Methodology workflow showing how HOMER evidence and adopted assumptions are processed through the Python calculation workflow.

The workflow separates the HOMER-native modelling tasks from the external TES calculation. HOMER Pro is used where the components are represented directly, including the generator, grid interface, converter and BESS. Python is used for the TES pathway and post-processing

calculations, including MWh-flex, annualised cost, sensitivity analysis and Monte Carlo sampling. This separation is retained throughout the methodology and case structure.

3.1.1 HOMER PRO modelling

The study combines a published net NGCC+CCS reference operating point, a simplified HOMER Pro representation and an external TES calculation. Case 0 represents the plant electrically as a generic generator connected to the grid, with a prescribed thermal-demand profile served by recovered generator heat and a backup boiler. The BESS cases add a converter and battery. Separate steam-turbine extraction, capture-process and auxiliary-load components are not represented in HOMER.

The BESS pathway is simulated using HOMER-native electrical-storage components. TES charging and discharge are calculated externally in Python using the retained hourly thermal-demand and electricity-price profiles; they do not modify the HOMER plant model. The external TES calculation represents heat shifting associated with CCS solvent regeneration, including the electrical opportunity cost of charging and the assumed electricity recovery from reduced steam extraction during discharge.

Figure 3-2 illustrates the conceptual NGCC+CCS+TES configuration used to define the plant side thermal-flexibility boundary. The figure shows that TES is connected to the CCS reboiler heat-supply pathway: stored heat is discharged only to the reboiler, while electrical-equivalent flexibility arises from reduced contemporaneous steam extraction rather than from direct electricity generation by TES.

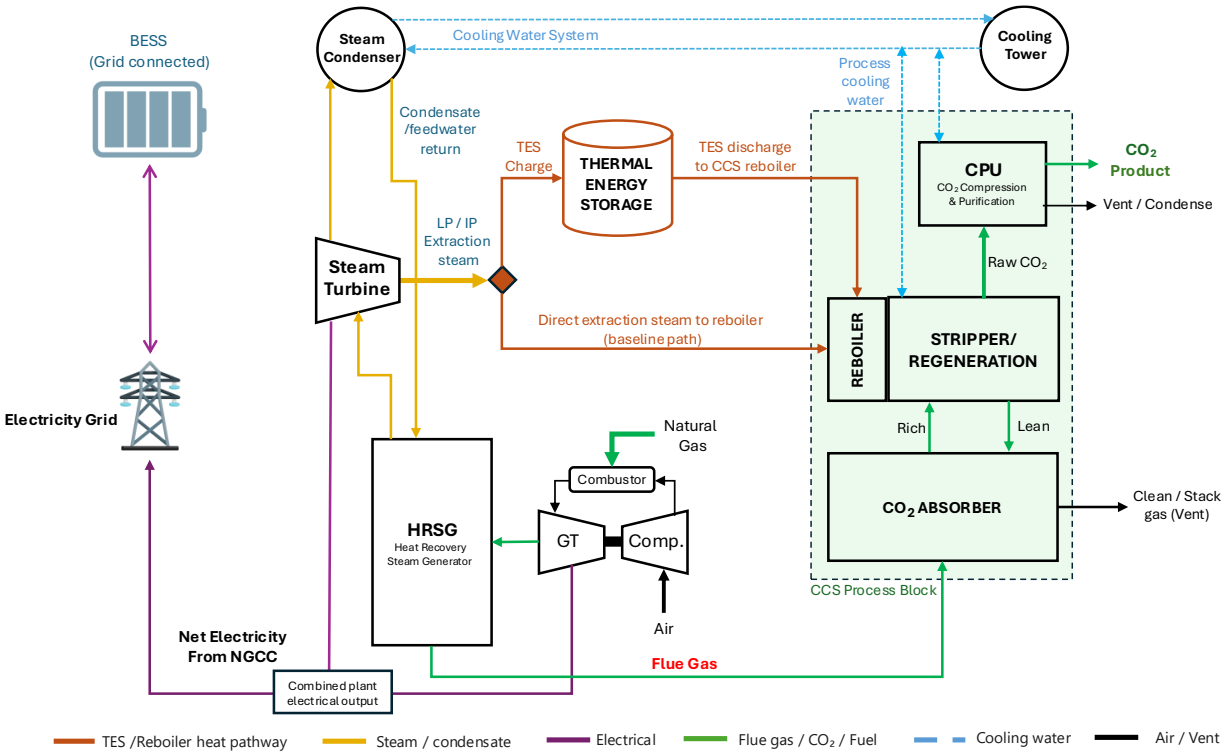


Fig. 3-2: Conceptual NGCC+CCS configuration with plant-integrated TES for reboiler heat; electrical and feedwater systems are shown in simplified form.

Figure 3-3 presents the modelling boundary adopted for the HOMER and Python workflow. The schematic separates the HOMER-native electrical BESS pathway from the external TES calculation applied to the reboiler thermal pathway. This structure preserves the distinction between electrical storage represented directly in HOMER Pro and reboiler-side thermal shifting calculated outside the HOMER component library.

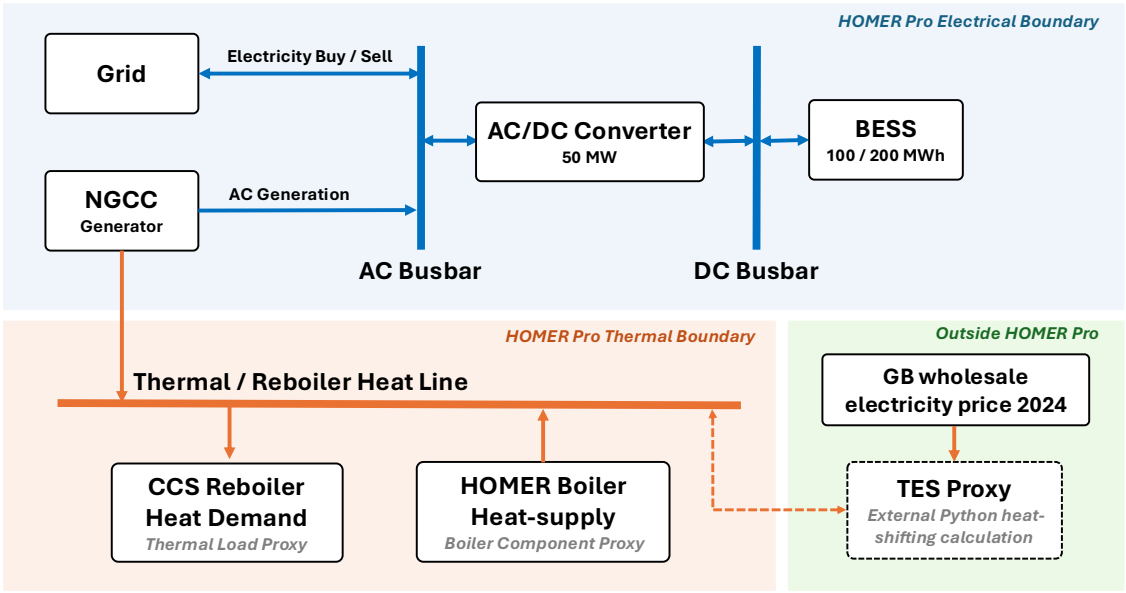


Fig. 3-3: HOMER Pro model schematic and external TES proxy boundary.

The diagram distinguishes the HOMER electrical and thermal balances from the external TES calculation. Its dashed connection indicates the modelling interface, not a demonstrated physical heat supply. TES charging assumes additional steam-cycle heat diversion, while useful discharge replaces live-steam extraction. The steam-extraction response and available electrical headroom are not explicitly simulated in HOMER.

3.1.2 Input data

The adopted 630.8 MW rating is taken from the baseline configuration without lean-vapour compression at full gas-turbine load in Alruwaili et al. (2025, Table 6). Gas-turbine output of 485.4 MW and steam-turbine output of 202.8 MW, less 57.4 MW of auxiliaries, give 630.8 MW net electrical output. This is a CCS-adjusted reference operating point. Adopting this rating does not establish that the simplified HOMER model reproduces the source plant across its operating range or that additional turbine-generator and grid-export capacity is available.

The market-price input is derived from 2024 GB Market Index Price data obtained through the Elexon BMRS Insights Solution (Elexon, n.d.). The retained series contains 17,520 half-hourly observations, excluding 29 February, represented by 8,760 hourly observations. The source settlement sequence retains 46 and 50 half-hourly observations on the spring and autumn clock-change days, respectively. The exported hourly prices can be reconstructed by rounding

half-hourly prices to three decimal places in £/kWh using ties-to-even rounding, then averaging adjacent pairs. This reconstruction describes the retained numerical sequence; it does not establish a separately documented calendar-time correction procedure. The dataset is treated as a representative model year rather than complete calendar-year 2024 coverage. Further preparation details are provided in Appendix B.3.

The processed wholesale-price profile provides the market signal for the HOMER dispatch representation, BESS charging and discharging behaviour, and the TES percentile-based charge-discharge rule. Prices were converted from GBP/MWh to GBP/kWh where required by the calculation workflow. Contains BMRS data © Elexon Limited copyright and database right 2024.

The prescribed reboiler-load scenario uses five load fractions: 0.60, 0.70, 0.80, 0.90 and 1.00. Each prepared fraction is multiplied by the adopted 630.8 MW reference output and a heat factor of 0.3915 kWth/kWe. The heat factor is a study modelling input, not a universal NGCC+CCS heat-duty constant. A multiplier of 1.10 defines an assumed elevated-heat-demand reference scenario; it is not a measured plant condition or a standard CCS allowance. Averaging adjacent half-hour thermal inputs produces nine hourly demand levels and reproduces the exported profile within rounding. The preparation was intended to associate the load fractions with price bands, but the retained fraction and price columns do not consistently preserve the intended same-hour mapping. The calculations use the retained HOMER export as their common hourly input basis.

The thermal-demand profile is a prescribed screening scenario, not an independently calibrated plant-operating record. Its input sequence is traceable to the retained upload and saved HOMER project, but the preparation alignment discrepancy remains unresolved. The results are therefore conditional on the adopted price and thermal profiles. The effect of correcting their alignment on flexibility costs and the technology comparison has not been established.

The HOMER model uses a natural-gas price of £0.30/m³ and the linear generator fuel relationship $F \approx 10{,}967.693235 + 0.184482638764P$, where F is fuel consumption in m³/h and P is electrical output in kW. The generator capital input is £300/kW, equivalent to £189.24 million at the adopted rating. These inputs were confirmed from the original HOMER project settings. Their external provenance remains incomplete: the gas-price reference year, fuel-curve calibration basis and equipment scope of the generator capital input are not documented.

Battery initial and replacement costs are set at £165/kWh of nominal capacity, adopted as a 2025 cost-scenario assumption. Replacement unit costs are held constant in real terms. The converter is costed separately at £300/kW, giving £15 million for the 50 MW rating. Initial battery-plus-converter costs are therefore £31.5 million for BESS-100 and £48 million for BESS-200. This component-cost boundary excludes a separately identified allowance for site-specific balance-of-plant and grid-connection works. External fixed operation and maintenance costs are set at £250,000 per year for each case.

The headline BESS calculation includes a non-wholesale revenue adjustment derived from Modo Energy's 2024 revenue-component databook (Jennings, 2025a). Monthly annualised rates are weighted by the calendar days in each month across the 366-day reporting year, with wholesale revenue excluded because electricity trading is already represented in the HOMER cash flows. The resulting adjustment is £34,328.81/MW-year, applied to the full 50 MW converter rating in each case, giving £1,716,440.33/year. Application to the full converter rating is a screening assumption. The supplementary SOC-constrained sensitivity uses a separate accounting boundary without this adjustment.

Table 3-1 summarises the principal inputs, assumptions and source bases. The TES calculation applies chronological hourly state-of-charge constraints, including charging curtailment at full capacity, discharge limitation when stored energy is insufficient, and cyclic annual SOC closure. The reference dispatch rule permits charging at or below the 40th price percentile and discharging at or above the 60th percentile. Alternative thresholds are evaluated in the sensitivity analysis.

The TES reference duration is four hours. The duration sensitivity evaluates 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 hours. Thermal round-trip efficiency is set at 90%, with equal charging and discharging efficiencies of $\sqrt{0.90}$, approximately 0.9487, applied in the chronological SOC calculation.

Table 3-1: Principal input data and modelling assumptions.

Parameter	Adopted value / range	Role in the model	Source basis
Time resolution	8,760 hourly observations	Common representative model-year sequence for HOMER and Python calculations; excludes 29 February.	Prepared from 17,520 half-hourly observations. Processing and clock-change treatment are described in Section 3.1.2 and Appendix B.3.
Wholesale electricity price	GB Market Index Price profile derived from 2024 data	Price signal for HOMER operation and the external TES dispatch rule.	Elexon BMRS / Insights Solution Market Index Price data (Elexon, n.d.), processed into the retained hourly sequence.
Adopted net NGCC+CCS reference output	630.8 MW	Defines the generator reference rating and scales the prescribed reboiler-load proxy.	Alruwaili et al. (2025), Table 6: baseline configuration without lean-vapour compression at full gas-turbine load. Net output includes steam-extraction and auxiliary penalties at that reference point.
Natural-gas price	£0.30/m³	Converts generator fuel consumption into fuel cost.	Original HOMER project settings; provenance qualifications in Section 3.1.2.
Generator fuel relationship	F ≈ 10,967.693235 + 0.184482638764P	Relates fuel consumption F (m³/h) to electrical output P (kW).	Original HOMER project settings.

Parameter	Adopted value / range	Role in the model	Source basis
Generator capital cost	£300/kW; £189.24 million total	Generator capital input for the common plant representation.	Original HOMER project settings; equipment scope qualification in Section 3.1.2.
CCS reboiler thermal load	Prescribed hourly thermal-demand profile	Represents reboiler heat demand in the simplified HOMER model and supplies the thermal input to the external TES calculation.	Study-defined profile retained in the HOMER hourly export. The unresolved price–thermal alignment limitation is described in section 3.1.2.
Reboiler heat factor	0.3915 kWth/kWe	Converts the prescribed electrical-output proxy into thermal demand before applying the heat-demand multiplier.	Adopted study modelling input; not a universal NGCC+CCS heat-duty constant.
Heat-stress multiplier	1.10 reference; 1.00 supplementary comparison	Defines an assumed 10% uplift in reference thermal demand. The supplementary comparison removes the uplift and resizes TES proportionally.	Study-defined scenario assumption; not a measured plant condition or standard CCS allowance.
TES technology	Plant-integrated sensible-hot TES	Reboiler-side thermal flexibility pathway	TES literature and technology-category source basis (IRENA, 2020; Skjervold and Nord, 2024).
TES integration boundary	Steam-cycle heat diverted during charging; stored heat supplied to the CCS reboiler during discharge.	Accounts for foregone electricity during charging and retained electricity from reduced steam extraction during discharge.	Study-defined integration boundary, described in Section 3.3.3.
TES reference dispatch rule	Charge at or below p40; discharge at or above p60	Defines the balanced symmetric reference charging and discharging windows	Study-defined modelling rule; not claimed to be optimal.
TES shift fraction	20% of eligible reboiler thermal load	Defines the thermal-shifting intensity under the reference case	Study-defined modelling assumption.
TES thermal round-trip efficiency	90% thermal	Represents TES thermal losses in the chronological SOC formulation	Literature-supported central assumption (IEA Energy Storage TCP, 2024; IRENA, 2024).
TES split efficiencies	$\eta ch = \eta dis = \sqrt{0.90} = 0.9487$	Applies equal charging and discharging efficiencies within the hourly SOC calculation	Adopted modelling convention derived from the 90% round-trip efficiency.
TES reference vessel duration	4 h	Defines the reference TES vessel capacity basis	Study-defined reference case only; not a proven optimum.
TES duration sensitivity	1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 h	Evaluates the effect of storage duration on useful discharge and MCF.	Study-defined sensitivity range; four hours is the reference duration.
TES central capex assumption	£40/kWh-th	Central TES annualised asset-cost assumption	Assumed central modelling case, informed by TES cost literature for plausibility context (Glatzmaier, 2011; IEA Energy Storage TCP, 2024; Jacob et al., 2017; Pompei et al., 2023); not a claimed market price.

Parameter	Adopted value / range	Role in the model	Source basis
TES capex sensitivity range	£25-60/kWh-th	Tests TES installed-cost sensitivity and break-even conditions	Study-defined modelling range: low range £25-30/kWh-th; high range £50-60/kWh-th.
TES fixed O&M	1% of TES capex per year	Fixed annual operating-cost allowance included in TES annual net cost.	Adopted screening-level assumption. The 1%/yr allowance is consistent with institutional liquid-salt TES analogue evidence (IEA Energy Storage TCP, 2024), but is not a site-specific O&M estimate for the modelled reboiler-grade retrofit.
Charging opportunity-cost conversion factor	0.28 kWe/kWth	Converts accepted charging heat into foregone electrical output for valuation.	Adopted screening coefficient; steam-extraction accounting is described in Section 3.3.3.
Discharge electricity-retention factor	0.28 kWe/kWth	Converts useful heat supplied to the reboiler into retained electrical output.	Adopted screening coefficient; steam-extraction accounting is described in Section 3.3.3.
BESS capacity cases	100 MWh and 200 MWh	Electrical-storage comparison cases	HOMER case definition.
BESS converter rating	50 MW	AC-side power rating and basis for the non-wholesale revenue adjustment.	HOMER case definition.
Battery initial and replacement cost	£165/kWh of nominal battery capacity	Determines battery purchase and replacement costs; replacement unit costs remain constant in real terms.	Study-defined 2025 cost scenario; component scope described in Section 3.1.2.
Converter capital cost	£300/kW; £15 million for 50 MW	Accounts for converter capital separately from battery capital.	Original HOMER project settings.
External fixed BESS O&M	£250,000/year	Adds an annual fixed operating-cost allowance to the BESS cost calculation.	Study-defined allowance equivalent to £5/kW-year at 50 MW.
BESS non-wholesale revenue adjustment	£34,328.81/MW-year; £1,716,440.33/year per 50 MW case	Reduces annual net cost in the headline BESS calculation.	Calculated from Modo Energy's 2024 monthly revenue components, excluding wholesale revenue (Jennings, 2025a).
Real discount rate	8%	Discounts and annualises cash flows in the revised TES–BESS comparison.	Study financial assumption; treatment described in Section 3.3.1.
Project life	25 years	Defines the financial assessment horizon.	Adopted assessment period, consistent with the IEAGHG gas-fired CCS benchmark (IEAGHG, 2012).
Capital recovery factor	0.093678779/year	Converts present cost into an equivalent annual cost.	Calculated using Equation 3-1 with r = 0.08 and n = 25 years.

TES is represented as sensible-heat storage supplying the CCS solvent-regeneration reboiler. Useful discharge is assumed to deliver heat at suitable temperature and pressure; storage temperature and pressure evolution are not simulated. Steam accumulators and pressurised hot-water storage provide the conceptual technology context. Skjervold and Nord (2024)

examine steam-accumulator flexibility in a coal-fired plant with solid-sorbent capture, illustrating the steam-extraction heat-shifting principle in that configuration.

The central TES installed-cost assumption is £40/kWh-th, with sensitivity analysis over £25–£60/kWh-th. Sensible-heat and liquid-salt storage studies provide cost context across different media, temperatures and integration arrangements (Glatzmaier, 2011; Jacob et al., 2017; Pompei et al., 2023; IEA Energy Storage TCP, 2024). The adopted cost range is used to assess how installed-cost uncertainty affects TES MCF and the cost-parity thresholds.

3.2 Model case structure

The modelling framework comprises a no-storage NGCC+CCS reference case and two storage pathways. Case 0 provides the hourly electrical output, thermal demand and electricity prices used in the analysis. Case 1 represents reboiler-side TES through an external chronological SOC model. Cases 2A and 2B represent 100 MWh and 200 MWh BESS configurations, respectively, each connected through a 50 MW converter. A supplementary Python calculation examines both battery capacities under an SOC-constrained, price-responsive operating policy.

Table 3-2 summarises the cases and their analytical roles. TES annual net cost comprises annualised installed capital cost, fixed O&M and accepted-charging opportunity cost, less the value of electricity retained during useful discharge. The headline BESS calculation uses incremental cash flows relative to Case 0, reassessed at 8% real, with external fixed O&M and the non-wholesale revenue adjustment. Section 3.3 defines the cost equations and pathway-specific MWh-flex denominators.

Table 3-2: Model case structure, tool boundary and analytical role.

Case	Description	Modelling tool	System boundary	Main analytical output
Case 0	No-storage NGCC+CCS reference	HOMER Pro	Generic generator, grid connection and prescribed thermal demand supplied by recovered heat and a backup boiler.	Hourly electrical and thermal outputs, grid exchanges and reference cash flows.
Case 1	Reboiler-side sensible-heat TES	Python chronological SOC model	Steam-cycle heat diversion during charging and useful stored heat supplied to the CCS reboiler during discharge.	Accepted charging, charging spill, useful discharge, unmet discharge requests, SOC, electrical-equivalent MWh-flex and TES MCF.
Case 2A	100 MWh BESS with a 50 MW converter	HOMER Pro with Python financial reassessment	Grid-connected battery and converter; original operating schedule with revised financial treatment.	AC electrical output, incremental annual net cost and headline BESS MCF.
Case 2B	200 MWh BESS with a 50 MW converter	HOMER Pro with Python financial reassessment	Increased battery energy capacity at the same converter rating; original operating schedule with revised financial treatment.	AC electrical output, incremental annual net cost and the effect of increased battery capacity on headline MCF.

Case	Description	Modelling tool	System boundary	Main analytical output
Supplementary BESS sensitivity	SOC-constrained operation of both battery capacities	Python daily price-responsive optimisation	20–80% SOC range with daily SOC closure; battery-only asset costing and wholesale trading cash flows.	SOC trajectories, charging and AC discharge, realised cycling, replacement timing and sensitivity MCF.

Case 0 supplies the common hourly input sequence for TES and the reference cash flows for the incremental BESS calculation. The TES reference uses a four-hour storage duration and the p40/p60 dispatch rule. The duration sensitivity covers one to 72 hours, as specified in Section 3.4.

The original HOMER capacity search evaluated 100, 200 and 400 MWh at a fixed 50 MW converter rating. The 100 MWh configuration had the lowest system NPC among those tested under the original financial settings and was selected as Case 2A. Case 2B retains the 200 MWh configuration to examine the effect of increasing energy capacity at unchanged converter power. Both operating schedules are retained for the revised financial assessment.

The supplementary BESS sensitivity evaluates both capacities using daily price-responsive dispatch within a 20–80% SOC range, with each model day beginning and ending at 50% SOC. Its operating assumptions and cost boundary are specified separately in Section 3.4 and Appendix D.

3.3 Flexibility and cost formulation

The analysis evaluates storage costs on an annualised basis. Capital costs are annualised using the capital recovery factor, and operating costs and electricity values are included according to each pathway's accounting boundary. Annual net cost is divided by the credited electrical flexibility, expressed as MWh-flex, to calculate the marginal cost of flexibility.

3.3.1 Annualisation

The capital recovery factor (CRF) converts a present capital cost into an equivalent annual cost. The real annual discount rate is denoted by r, expressed as a decimal, and the project lifetime by n, expressed in years. Equation 3-1 gives the standard capital-recovery relationship (Jenkin et al., 2019):

$$CRF = \frac{r(1+r)^n}{(1+r)^n - 1} \tag{3-1}$$

Equation 3-2 calculates the annualised capital cost, C_{ann}, in £/year, from the component capital cost, C_{capex}, in pounds, and the capital recovery factor:

$$C_{ann} = C_{capex} \times CRF \tag{3-2}$$

The revised flexibility-cost comparison applies a common real discount rate of 8% over a 25-year assessment period, giving a capital recovery factor of 0.093678779/year. Cash flows are evaluated in constant-price terms, with no additional general inflation escalation. The discount rate is varied in the sensitivity analysis.

The original HOMER projects specify an 8% nominal discount rate and 2% expected inflation, corresponding to a real rate of approximately 5.8824%. For the revised BESS comparison, initial investment, replacement expenditure, remaining-life salvage and recurring grid cash flows were reconstructed from the original model records and discounted at 8% real before annualisation. The original operating schedules, replacement timings and annual AC-export quantities were retained. The financial reassessment therefore evaluates those operating cases on the common revised discount basis.

3.3.2 Marginal cost of flexibility

The marginal cost of flexibility (MCF) is defined here as the average incremental net cost per credited MWh-flex. It applies the cost-normalisation principle used in levelised-cost-of-storage analysis (Schmidt et al., 2019), with specified electricity values and revenue adjustments included in the numerator. MCF therefore expresses a net cost under the stated accounting assumptions; it is neither a required electricity selling price nor a marginal-cost derivative.

In Equation 3-3, MCF_j is expressed in £/MWh-flex, C_j is the annual net cost of pathway j in £/year, and $MWh_{flex,j}$ is its annual credited flexibility. For TES, this denominator is the retained electrical output inferred from useful reboiler heat discharge using the adopted electricity-retention factor. For BESS, it is the accumulated AC inverter output exported to the grid. These definitions provide a common cost-normalisation unit while preserving the distinct physical services of the two pathways. Table B-3 summarises the denominator definitions.

For storage pathway $_j$, Equation 3-3 relates annual net cost to annual credited flexibility:

$$MCF_j = C_j / MWh_{flex,j} \tag{3-3}$$

The TES cost calculation combines annualised asset costs with charging opportunity cost and discharge-related electricity value. The annual asset cost, $C_{asset,TES}$, comprises capital recovery and fixed operation and maintenance (O&M). Here, $C_{cap,TES}$ is installed TES capital cost in pounds, and $C_{O\&M,TES}$ is annual fixed O&M cost in £/year. Equation 3-4 calculates the annual asset cost:

$$C_{asset,TES} = CRF \times C_{cap,TES} + C_{O\&M,TES} \tag{3-4}$$

Annual TES net cost is denoted by C_{TES}. The accepted-charging opportunity cost, $C_{opp,ch}$, is the annual value of electrical output foregone during charging. The useful-discharge electricity value, $V_{eq,dis}$, is the annual value of electricity retained through reduced reboiler steam extraction. Both are calculated using the corresponding hourly electricity prices and expressed in £/year. Equation 3-5 combines these terms with annual asset cost:

$$C_{TES} = C_{asset,TES} + C_{opp,ch} - V_{eq,dis} \quad (3\text{-}5)$$

The TES marginal cost of flexibility, MCF_{TES}, is expressed in £/MWh-flex. Its denominator, $MWh_{flex,TES}$, is the annual electrical-equivalent flexibility credited to useful TES discharge. Equation 3-6 divides annual TES net cost by this quantity:

$$MCF_{TES} = C_{TES} / MWh_{flex,TES} \quad (3\text{-}6)$$

3.3.3 TES heat-shifting

The TES model represents chronological heat storage supplying the CCS solvent-regeneration reboiler. During charging, additional steam-cycle heat is diverted into storage, and the associated foregone electrical output is included as an opportunity cost. During discharge, useful stored heat replaces contemporaneous live-steam extraction for the reboiler, allowing electrical output to be retained. These electrical effects are calculated externally using the adopted conversion factors.

The reference dispatch rule permits charging at or below p40 and discharging at or above p60, with no requested operation between the thresholds. The corresponding prices are £69/MWh and £79/MWh in the adopted hourly series. Alternative percentile combinations are evaluated in Section 3.4.

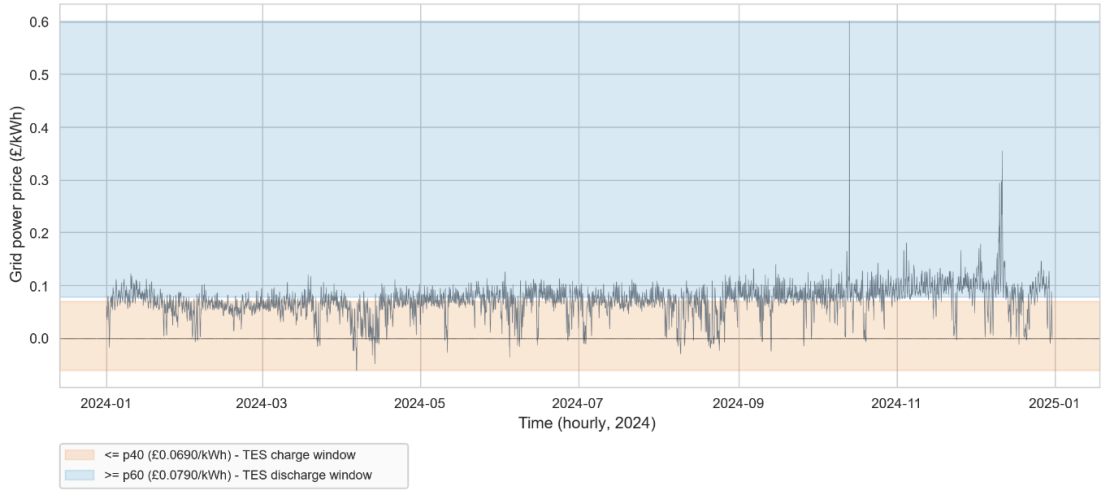


Fig. 3-4: TES reference dispatch thresholds in the adopted 8,760-hour price series: p40 = £69/MWh for charging and p60 = £79/MWh for discharging.

Brown et al. (2018) describe a general multi-period storage formulation within the PyPSA power-system modelling framework, including energy balances, charging and discharging efficiencies, capacity constraints and cyclic SOC conditions. This study applies that established structure to reboiler-side thermal storage, with heat-demand-linked requests, prescribed percentile dispatch and electrical-equivalent cost accounting. Equations 3-12 to 3-18 express the chronological storage constraints used here.

Here, α is the TES shift fraction, set at 0.20 in the reference case. $Q_{reb,t}$ denotes reboiler heat demand during interval t, expressed in kWh-th. The imported thermal-power value in kW-th is multiplied by the time-step duration, $\Delta t = 1$ h, to obtain this interval energy. The electricity price p_t and thresholds p_{ch} and p_{dis} are expressed in £/kWh; the reference thresholds are therefore £0.069/kWh and £0.079/kWh. Charging and discharging requests are mutually exclusive. For sensitivity cases with coincident thresholds, hours exactly at the shared threshold receive neither request.

The requested charging heat and requested useful heat discharge during interval t are denoted by $Q_{ch,req,t}$ and $Q_{dis,req,t}$, respectively, both in kWh-th. The indicator function $I(\cdot)$ equals one when its condition is satisfied and zero otherwise. Equations 3-7 and 3-8 define these requests before storage constraints are applied:

$$Q_{ch,req,t} = \alpha\, Q_{reb,t}\, I(p_t \le p_{ch}) \tag{3-7}$$

$$Q_{dis,req,t} = \alpha\, Q_{reb,t}\, I(p_t \ge p_{dis}) \tag{3-8}$$

The maximum TES thermal charging or discharging rate, $P_{TES,max}$, is expressed in kW-th. It is calculated from the shifted share of peak reboiler thermal power, obtained by dividing interval heat demand by the interval duration:

$$P_{TES,max} = \alpha\, \max_t(Q_{reb,t} / \Delta t) \tag{3-9}$$

The stored-energy capacity E_{TES} is calculated from the thermal power rating $P_{TES,max}$ and the nominal storage duration h_{TES}, following the power–duration sizing relationship described by Bowen et al. (2019). With power expressed in kW-th and duration in hours, Equation 3-10 gives capacity in kWh-th:

$$E_{TES} = h_{TES}\, P_{TES,max} \tag{3-10}$$

The reference thermal power rating is 54.3308 MW-th. A nominal duration of four hours gives a stored-energy capacity of 217.3232 MWh-th. The duration sensitivity evaluates 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 hours at the same reference thermal power rating.

The dimensionless thermal round-trip efficiency is denoted by η_{TES}. Charging efficiency, η_{ch}, determines the fraction of accepted heat added to storage, while discharging efficiency, η_{dis}, determines the fraction of withdrawn stored energy delivered as useful heat. Equation 3-11 divides the round-trip efficiency equally between these two stages:

$$\eta_{ch} = \eta_{dis} = \sqrt{\eta_{TES}} \tag{3-11}$$

The reference thermal round-trip efficiency is 0.90, giving equal charging and discharging efficiencies of approximately 0.9487.

Accepted charging heat during interval t is denoted by $Q_{ch,acc,t}$, in kWh-th. The state of charge, SOC_{t-1}, is the stored thermal energy at the beginning of the interval, also in kWh-th. Equation 3-12 limits accepted charging by the requested heat, the thermal rate limit and the available storage capacity. Dividing the remaining capacity by charging efficiency converts that space into an admissible heat input:

$$Q_{ch,acc,t} = \min[Q_{ch,req,t},\ P_{TES,max}\,\Delta t,\ (E_{TES} - SOC_{t-1}) / \eta_{ch}] \tag{3-12}$$

Charging spill, $Q_{spill,t}$, is the requested heat that cannot be accepted during interval t, expressed in kWh-th. It is calculated as:

$$Q_{spill,t} = Q_{ch,req,t} - Q_{ch,acc,t} \tag{3-13}$$

Useful heat delivered to the CCS reboiler during interval t is denoted by $Q_{dis,use,t}$, in kWh-th. Equation 3-14 limits this delivery by the discharge request, the thermal rate limit and the useful heat recoverable from the stored energy:

$$Q_{dis,use,t} = \min[Q_{dis,req,t},\ P_{TES,max}\,\Delta t,\ \eta_{dis}\,SOC_{t-1}] \tag{3-14}$$

The unmet TES discharge request, $Q_{unmet,t}$, is the difference between requested and delivered useful heat during interval t, in kWh-th. It measures a shortfall in the requested TES contribution rather than unserved total reboiler demand:

$$Q_{unmet,t} = Q_{dis,req,t} - Q_{dis,use,t} \tag{3-15}$$

The end-of-interval stored thermal energy is denoted by SOC_t, in kWh-th. Equation 3-16 updates the preceding inventory by adding efficiency-adjusted accepted charging and subtracting the stored energy withdrawn to provide useful discharge:

$$SOC_t = SOC_{t-1} + \eta_{ch}\,Q_{ch,acc,t} - Q_{dis,use,t} / \eta_{dis} \tag{3-16}$$

Stored thermal energy must remain between zero and the vessel capacity E_{TES} in every interval:

$$0 \le SOC_t \le E_{TES} \tag{3-17}$$

T denotes the final hourly interval of the model year. The cyclic condition requires the final stored-energy inventory to equal its initial value, so annual charging and discharge are evaluated without a net change in stored energy.

With SOC_0 denoting the initial stored-energy inventory and SOC_T the final inventory, the cyclic annual condition is:

$$SOC_T = SOC_0 \tag{3-18}$$

Annual thermal quantities are obtained by summing their interval values. $Q_{x,ann}$ denotes the annual total in kWh-th, and $Q_{x,t}$ denotes the corresponding quantity during interval t. The index

x identifies requested charging, accepted charging, charging spill, useful discharge or unmet discharge. Equation 3-19 gives this aggregation:

$$Qx, ann = \Sigma t\ Qx, t,\ \ x \in \{ch, req;\ ch, acc;\ spill;\ dis, use;\ unmet\} \quad (3\text{-}19)$$

Annual TES electrical-equivalent flexibility, $MWh_{flex,TES}$, is calculated from annual useful reboiler heat discharge, $Q_{dis,use,ann}$, in kWh-th. The steam-extraction conversion factor, φ_{te}, is 0.28 kWe/kWth in the reference case; Appendix C.4 explains its benchmark basis using IEAGHG (2012). Multiplication gives retained electrical energy in kWh, and division by 1,000 converts it to MWh-flex:

$$MWh_{flex,TES} = \varphi_{te}\ Q_{dis,use,ann} / 1000 \quad (3\text{-}20)$$

The credit represents reduced live-steam extraction for the reboiler, with fired-boiler heat excluded from this mechanism. The same reference coefficient is applied to charging opportunity cost. Both coefficients vary together over 0.18–0.35 kWe/kWth in the sensitivity analysis. This constant-factor representation approximates the steam-cycle response, while delivery of the calculated electrical increment depends on the headroom conditions discussed in Section 3.6.

The superscript AB denotes the annual energy-balance benchmark. Its value is the smaller of total requested charging multiplied by the thermal round-trip efficiency and total requested useful discharge. The benchmark retains the prescribed dispatch requests and efficiency while removing hourly chronology and vessel-capacity constraints. It does not establish the physical availability of charging heat or electrical headroom. Charging spill is reported separately as a fraction of requested charging, so spill and retention have different denominators.

The retention ratio, R_{ret}, expresses annual useful discharge as a percentage of the annual energy-balance benchmark, denoted by $Q_{dis,ann}$ with superscript ^{AB}. Both heat quantities are expressed in kWh-th. Equation 3-21 measures the share of the benchmark realised under chronological storage constraints:

$$R_{ret} = (Q_{dis,use,ann} / Q_{dis,ann}^{AB}) \times 100\% \quad (3\text{-}21)$$

Annual equivalent full TES cycles are denoted by N_{EFC}. This quantity divides the annual energy entering storage after charging losses by the stored-energy capacity. The numerator is accepted annual charging heat, $Q_{ch,acc,ann}$, multiplied by η_{ch}; both this energy and E_{TES} are expressed in kWh-th. This uses the storage-throughput boundary described by HOMER Energy (n.d.), after charging losses and before discharging losses:

$$N_{EFC} = \eta_{ch}\ Q_{ch,acc,ann} / E_{TES} \quad (3\text{-}22)$$

Annual thermal loss, $Q_{loss,ann}$, is expressed in kWh-th. Under cyclic annual SOC closure, it equals accepted charging heat minus useful discharge:

$$Q_{loss,ann} = Q_{ch,acc,ann} - Q_{dis,use,ann} \quad (3\text{-}23)$$

Here, c_{TES} is the unit installed capital cost in £/kWh-th, and E_{TES} is the stored-energy capacity in kWh-th. Their product gives total installed capital cost in pounds. The reference unit cost is £40/kWh-th, with sensitivity analysis over £25–£60/kWh-th.

Installed TES capital cost is calculated as the product of unit capital cost and stored-energy capacity:

$$C_{cap,TES} = c_{TES}\, E_{TES} \quad (3\text{-}24)$$

In Equations 3-25 and 3-26, p_t is the hourly electricity price in £/kWh. $Q_{ch,acc,t}$ is accepted charging heat before charging losses, and $Q_{dis,use,t}$ is useful heat delivered to the reboiler after storage losses, both expressed in kWh-th per interval. The conversion factor φ_{te} translates these thermal quantities into electrical-equivalent energy. Summation over the 8,760 hourly intervals gives annual charging opportunity cost and retained-electricity value in pounds. Charging opportunity cost is added to annual TES cost, while retained-electricity value is deducted. The heat quantities already include the interval duration, so no additional time-step multiplier is required in these valuation equations.

Equations 3-25 and 3-26 calculate the annual electricity opportunity cost of accepted charging and the annual value of electricity retained during useful discharge, respectively. These terms are added to and subtracted from the annual asset cost in Equation 3-5:

$$C_{opp,ch} = \varphi_{te}\, \Sigma_t\, p_t\, Q_{ch,acc,t} \quad (3\text{-}25)$$

$$V_{eq,dis} = \varphi_{te}\, \Sigma_t\, p_t\, Q_{dis,use,t} \quad (3\text{-}26)$$

3.3.4 BESS cost

In Equation 3-27, NPC_{BESS} and NPC_0 denote present costs evaluated on the common revised discount basis. Common generator costs cancel between the retained cases. The incremental present cost is reconstructed from battery and converter investment, replacement expenditure, remaining-life salvage and differences in recurring grid cash flows. Replacement expenditure is discounted at its retained fractional-year timing, and salvage is valued at the end of year 25.

The headline BESS cases retain their original HOMER operating schedules and apply the financial reassessment described in Section 3.3.1. Net present cost represents the discounted value of costs less revenues over the assessment period. For the revised comparison, the BESS and Case 0 cash flows are evaluated on the common 8% real, 25-year basis. The incremental BESS present cost, ΔNPC_{BESS}, is the difference between the two present costs, expressed in pounds:

$$\Delta NPC_{BESS} = NPC_{BESS} - NPC_0 \quad (3\text{-}27)$$

$C_{O\&M,BESS}$ is the external fixed O&M allowance of £250,000/year for each case, equivalent to £5/kW-year at the 50 MW converter rating. $C_{ann,BESS}$ is the resulting annual cost before the non-wholesale revenue adjustment.

The incremental present cost is annualised using the same discount rate and assessment period. External fixed O&M is then added to obtain annual cost before the non-wholesale revenue adjustment:

$$C_{ann,BESS} = CRF \times \Delta NPC_{BESS} + C_{O\&M,BESS} \quad (3\text{-}28)$$

Wholesale trading is included in the incremental grid cash flows. The additional non-wholesale revenue rate, c_{nw}, is £34,328.81/MW-year, and the converter rating, P_{conv}, is 50 MW. Equation 3-29 calculates the annual non-wholesale revenue adjustment, C_{nw}, in £/year:

$$C_{nw} = c_{nw} \times P_{conv} \quad (3\text{-}29)$$

The annual adjustment is £1,716,440.33 for each headline BESS case. Annual net BESS cost after this adjustment is denoted by $C_{net,BESS}$, in £/year. It is calculated by subtracting the adjustment from annual cost:

$$C_{net,BESS} = C_{ann,BESS} - C_{nw} \quad (3\text{-}30)$$

Annual AC inverter output exported to the grid is denoted by $E_{inv,AC}$, in kWh. This quantity provides the annual credited BESS flexibility, $MWh_{flex,BESS}$, after conversion to MWh:

$$MWh_{flex,BESS} = E_{inv,AC} / 1000 \quad (3\text{-}31)$$

Battery-side throughput is used separately to assess cycling and replacement timing.

$MCF_{gross,BESS}$ denotes the cost per credited MWh-flex before the non-wholesale revenue adjustment. It divides $C_{ann,BESS}$ by annual BESS flexibility. Wholesale trading cash flows remain included in this annual cost:

$$MCF_{gross,BESS} = C_{ann,BESS} / MWh_{flex,BESS} \quad (3\text{-}32)$$

The headline BESS marginal cost of flexibility, MCF_{BESS}, is expressed in £/MWh-flex. It divides annual net cost after the non-wholesale adjustment by annual credited BESS flexibility and is used in the central comparison, parity analysis and Monte Carlo analysis:

$$MCF_{BESS} = C_{net,BESS} / MWh_{flex,BESS} \quad (3\text{-}33)$$

3.3.5 Comparative ratio

The dimensionless TES/BESS cost ratio is denoted by $R_{TES/BESS}$. It divides the TES MCF defined in Equation 3-6 by the headline BESS MCF defined in Equation 3-33:

$$R_{\mathrm{TES/BESS}} = {}^{\mathrm{MCF_{TES}}}/_{\mathrm{MCF_{BESS}}} \quad (3\text{-}34)$$

For a positive BESS MCF, a ratio below one indicates a lower TES MCF, while a ratio above one indicates a lower BESS MCF. Cost parity occurs when:

$$R_{TES/BESS} = 1 \tag{3-35}$$

The ratio compares costs under the specified configurations, dispatch rules and accounting boundaries. It expresses parity per credited MWh-flex, with technical capabilities considered separately. The 100 MWh BESS case is the primary comparator in the parity heatmap and main Monte Carlo comparison; the 200 MWh case provides a secondary comparison.

3.4 Sensitivity and uncertainty analysis

The TES–BESS comparison is extended through deterministic sensitivity analysis and Monte Carlo uncertainty propagation. The analysis examines TES dispatch thresholds, reboiler-load shape, storage duration, installed cost, the electricity-to-heat conversion factor, charging and discharging shift fraction, the BESS incremental net-present-cost multiplier, and the real discount rate. The BESS non-wholesale revenue adjustment remains fixed.

The TES dispatch sensitivity evaluates 25 combinations of charging thresholds at p10, p20, p30, p40 and p50 and discharging thresholds at p50, p60, p70, p80 and p90. The p40/p60 combination remains the reference rule. For the p50/p50 combination, hours with prices equal to the shared threshold are assigned neither charging nor discharging. The comparison assesses how threshold selection affects accepted charging, useful discharge and MCF.

The reboiler-load-shape sensitivity compares the reference hourly series with a flat profile having the same annual mean and an inverse-rank profile retaining the same distribution of load values. The dispatch thresholds, storage duration, shift fraction, efficiencies and cost assumptions remain unchanged. This comparison examines sensitivity to the hourly allocation of reboiler heat demand; it does not establish the correct historical alignment between prices and thermal demand.

TES storage duration is evaluated at 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 h, with 4 h retained as the reference. At a fixed thermal power rating, changing duration changes stored-energy capacity and installed cost. The chronological calculation determines the resulting accepted charging, useful discharge, electrical-equivalent flexibility and MCF.

Two additional TES diagnostics examine the assumed heat-demand multiplier and electrical headroom. The multiplier comparison uses 1.00 alongside the 1.10 reference and resizes TES in proportion to thermal demand, keeping the dispatch rule, duration and unit costs unchanged. It distinguishes proportional scaling of the model from the behaviour of a fixed-size installation.

The fixed-schedule headroom diagnostic limits the electrical credit from each useful-discharge hour to the smaller of the calculated increment and an illustrative additional-headroom limit above 630.8 MW. Limits of 0, 5, 10 and approximately 15.213 MW are examined. The TES schedule, charging opportunity cost and asset costs remain unchanged, while credited electrical output and its value are capped. This isolates the consequence of restricted electrical credit without redispatching the plant or establishing equipment capacity.

A supplementary SOC-constrained, price-responsive sensitivity evaluates the 100 MWh and 200 MWh BESS configurations, each with a 50 MW power rating. Dispatch is calculated over consecutive 24-hour model periods using perfect foresight of the hourly wholesale prices. SOC is restricted to 20–80% of nominal capacity and returns to 50% at the end of each period. Simultaneous charging and discharging are prohibited. The combined AC round-trip efficiency is 81.22%, divided equally between charging and discharging efficiencies. Cycling intensity follows from the dispatch calculation rather than an imposed daily equivalent-full-cycle ceiling.

The sensitivity uses a battery capital cost of £165/kWh, annual fixed O&M of £250,000, a 25-year appraisal period and an 8% real discount rate. Replacement timing is determined by the earlier of 6,000 equivalent full cycles or ten years. Annual net cost includes annualised battery and replacement costs, fixed O&M, wholesale charging expenditure and discharge revenue. Converter capital cost, salvage value and the non-wholesale revenue adjustment are excluded from this supplementary calculation. Its MCF therefore reflects both the revised operating constraints and its specified cost boundary; differences from the headline BESS results cannot be attributed solely to the narrower SOC range.

The remaining analysis comprises three stages. One-at-a-time sensitivity examines the influence of individual inputs, with the TES charging and discharging electricity-to-heat factors varied together. A two-dimensional cost-parity analysis combines TES installed cost with a multiplier on BESS incremental net present cost. Monte Carlo analysis propagates selected input uncertainties through 10,000 samples. The resulting distributions and proportions of samples favouring either technology are conditional on the specified input ranges and model assumptions. Table 3-3 summarises the analysis framework.

Table 3-3: Staged uncertainty analysis framework.

Analysis step	Parameters varied	Parameters used in this study	Analytical output
TES dispatch thresholds	Charging and discharging price percentiles	25 combinations: charging p10–p50 and discharging p50–p90, both in ten-percentile increments; p40/p60 reference	Accepted charging, useful discharge, spill and MCF
Reboiler-load shape	Hourly allocation of thermal demand	Reference series; flat profile with the same mean; inverse-rank profile with the same load distribution	Useful discharge, spill, retention, MWh-flex and MCF
TES storage duration	Stored-energy capacity at fixed thermal power	1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 h; 4 h reference	Accepted charging, useful discharge, MWh-flex and MCF
SOC-constrained BESS sensitivity	Battery capacity under a common dispatch method	100 and 200 MWh, each at 50 MW; 20–80% SOC; daily SOC closure; perfect price foresight	AC discharge, cycling intensity, replacement timing and MCF
One-at-a-time sensitivity	TES installed cost, paired electricity-to-heat factors, shift fraction, BESS incremental NPC multiplier and real discount rate	Individual variations around the reference assumptions; charging and discharging conversion factors varied together	Influence of each input on MCF

Analysis step	Parameters varied	Parameters used in this study	Analytical output
Cost-parity analysis	TES installed cost and BESS incremental NPC multiplier	£25–£60/kWh-th and multipliers of 0.60–1.40	Relative MCF and cost-parity boundary
Monte Carlo analysis	TES installed cost, paired electricity-to-heat factors, BESS incremental NPC multiplier and real discount rate	10,000 samples; fixed BESS non-wholesale revenue adjustment	MCF distributions and conditional proportions of samples with lower TES MCF

Figure 3-5 presents the analysis sequence from the reference case through deterministic screening and probabilistic uncertainty propagation.

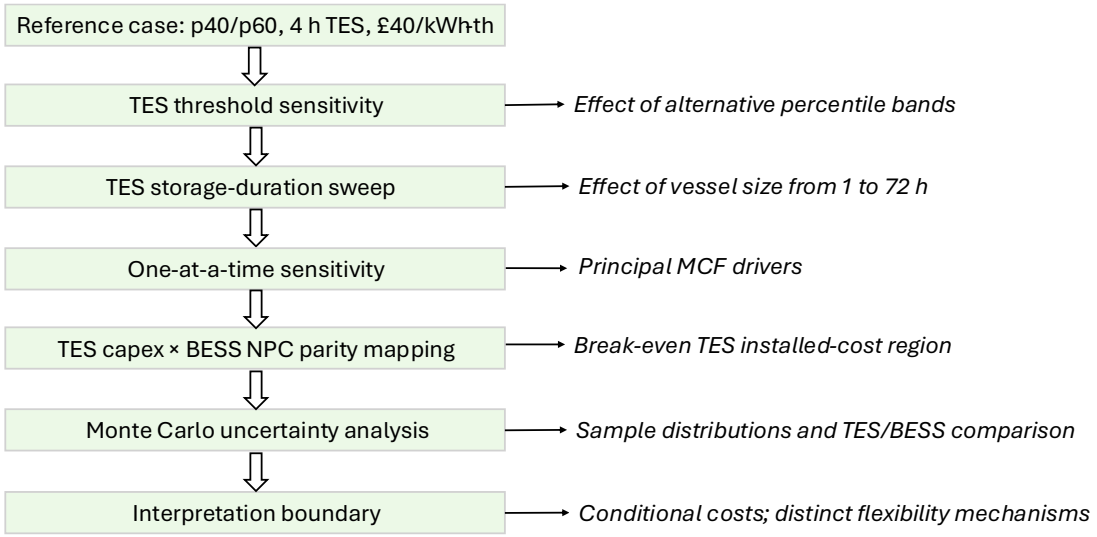


Fig. 3-5: Sensitivity and uncertainty analysis framework adopted in the study.

Table 3-4: Sensitivity and Monte Carlo ranges.

Parameter	Central / reference	Low	High	Distribution / method	Role
TES dispatch thresholds	p40/p60	Charging p10; discharging p50	Charging p50; discharging p90	25 combinations in ten-percentile increments	Effect of threshold selection on thermal dispatch and MCF
Reboiler-load shape	Reference hourly series	—	—	Reference, flat same-mean and inverse-rank same-distribution profiles	Sensitivity to the hourly allocation of thermal demand
TES storage duration	4 h	1 h	72 h	Deterministic sweep: 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 h	Effect of stored-energy capacity and associated cost
SOC-constrained BESS dispatch	100 and 200 MWh; 50 MW each	—	—	20–80% SOC; 50% initial and final SOC in each 24-hour period; perfect price foresight	Supplementary assessment of dispatch, cycling and MCF

Parameter	Central / reference	Low	High	Distribution / method	Role
TES charging and discharging electricity-to-heat factors	0.28 kWe/kWth	0.18 kWe/kWth	0.35 kWe/kWth	Varied together in OAT; one shared triangular draw in Monte Carlo, with mode 0.28	Charging opportunity cost and electricity retained during discharge
TES installed cost	£40/kWh-th	£25/kWh-th	£60/kWh-th	OAT and parity analysis; triangular Monte Carlo distribution with mode £40/kWh-th	TES capital cost
TES shift fraction	0.20	0.10	0.30	OAT only	Requested charging and discharging heat
BESS incremental NPC multiplier: OAT and Monte Carlo	1.00	0.85	1.15	OAT; triangular Monte Carlo distribution with mode 1.00	Sensitivity to BESS incremental lifecycle cost
BESS incremental NPC multiplier: parity analysis	1.00	0.60	1.40	Deterministic grid	Relative cost and parity boundary
Real discount rate	8%	6%	10%	OAT; uniform Monte Carlo distribution	Discounting of replacement and salvage cash flows and annualisation of costs
BESS non-wholesale revenue adjustment	£34,328.81 /MW-year	—	—	Fixed; not sampled	Annual adjustment of £1,716,440.33 for each 50 MW headline BESS case

The cost-parity analysis uses TES installed costs of £25, £30, £35, £40, £45, £50, £55 and £60/kWh-th and BESS incremental NPC multipliers spanning 0.60–1.40. The multiplier scales the reconstructed BESS incremental NPC, while the external fixed O&M and non-wholesale revenue adjustment remain unchanged. It represents a proportional change in incremental lifecycle cost rather than a battery purchase-price forecast. The hourly HOMER dispatch remains fixed throughout this analysis.

Monte Carlo analysis propagates the input distributions in Table 3-4 through 10,000 samples. The chronological dispatch schedules remain fixed, while the sampled TES conversion factor changes both charging opportunity cost and discharge-related electrical flexibility. For each sampled discount rate, BESS replacement and salvage cash flows are re-discounted and annual costs are recalculated. The resulting MCF distributions describe uncertainty within the specified operating and economic assumptions.

In Equation 3-36, P denotes the proportion of samples with a lower TES MCF, $N_{TES<BESS}$ is the number of such samples for the relevant BESS comparator, and N is the total sample count. Both MCF values use the net-cost definitions in Section 3.3.

Monte Carlo simulation is applied as an uncertainty-propagation method in which sampled input values are passed through the cost model to generate output distributions (Saltelli et al., 2008).

Equation 3-36 reports the proportion of samples in which TES has a lower MCF than the relevant headline BESS comparator:

$$P\left(MCF_{(TES)} < MCF_{(BESS)}\right) = N_{(TES<BESS)}/N \quad (3\text{-}36)$$

These sample proportions are conditional on the selected input distributions, retained dispatch schedules and accounting boundaries. They are not empirical probabilities that either technology will be cheaper in an operating project. Electrical headroom and price–thermal alignment remain separate limitations, as discussed in Section 3.6.

3.5 Internal consistency checks

The calculations were checked by reconciling the retained HOMER outputs with the quantities used in post-processing and examining storage energy balances and state-of-charge limits. Appendix E reports the numerical discrepancies and applicable tolerances. These checks assess consistency within the adopted equations and assumptions; they do not establish performance against operating-plant measurements.

The HOMER reconciliation compares retained annual summaries with totals calculated from the hourly exports. It covers generator and boiler output, BESS operating quantities and the distinction between battery-side energy and AC inverter output. Differences arising from the precision of the retained records are reported against stated numerical tolerances.

The storage checks examine hourly and annual energy balances, SOC bounds and boundary closure. For TES, accepted charging and useful discharge are checked against their requests, power limits and available storage capacity or inventory. Spill and unmet discharge are non-negative. The supplementary BESS calculation is checked for energy balance, SOC limits and terminal SOC closure in each 24-hour period.

The input review distinguishes assumptions supported by specific literature or source records from study-defined scenarios. It considers the source system, operating conditions and cost boundary when assessing relevance. This review provides context for the adopted inputs rather than a numerical validation score.

Table 3-5 summarises the checking methods. Appendix E presents the numerical reconciliation evidence, while Chapter 4 discusses its implications for the reported results.

Table 3-5: Internal consistency checking methods.

Check layer	Basis	Check focus	Checking criterion	Interpretation boundary
HOMER–Python reconciliation	Outputs	Annual summaries and hourly-export totals; battery-side and AC-side energy quantities.	Differences are reported against the stated numerical tolerances.	Consistency between retained records and post-processing.
Storage energy and SOC checks	Balances	Hourly and annual energy balances, SOC limits, TES requests and daily BESS SOC closure.	Balances close within numerical tolerances; capacity, power and request limits are respected.	Consistency of the storage calculations under the adopted constraints.

Input evidence review	Sources	Technical, financial and cost assumptions, including differences in source conditions.	Specific source support and study-defined assumptions are distinguished.	Context and applicability of evidence; no numerical validation score.
Financial reconciliation	Cash flows	Initial costs, replacement timing, salvage, grid cash flows and external adjustments.	Retained cash flows are discounted and annualised on the stated financial basis.	Consistency of the revised cost accounting; no new dispatch optimisation.

The financial reconciliation checks initial costs, replacement timing, remaining-life salvage and recurring cash flows against the retained source records. The revised calculation discounts these cash flows at the common real rate before annualization and keeps the external O&M and non-wholesale revenue adjustment separately identifiable.

The checks establish the relationship between the retained data, displayed equations and calculated quantities. The absence of operating-plant validation, and its implications for the physical interpretation of the results, are addressed in Section 3.6.

3.6 Modelling scope and limitations

The modelling boundary is defined by a screening-level techno-economic comparison of two distinct flexibility pathways around a common NGCC+CCS reference case. Plant-integrated TES acts on the CCS solvent-regeneration reboiler-side thermal coupling, whereas grid-scale BESS acts externally at the electrical interface. The common MWh-flex denominator is used as a cost-normalisation basis and does not imply capability equivalence or identical grid-service provision.

NGCC+CCS representation: The HOMER baseline combines a generic generator, grid connection, prescribed thermal demand, recovered heat and backup boiler. The 630.8 MW rating is a published net NGCC+CCS operating point, but hourly steam-extraction and auxiliary-load variations are not explicitly calculated. The reference auxiliary allowance must not be deducted again from this net rating. The reboiler profile is a prescribed demand scenario rather than a dynamically simulated capture process.

The Case 0 baseline also represents a high-utilisation annual operating profile. Planned and unplanned outages and detailed start-stop scheduling are not modelled explicitly.

The adopted profile is a high-utilisation screening baseline rather than a forecast of future residual-balancing operation. This basis remains analytically relevant because NGCC+CCS benchmark studies commonly evaluate sustained operation and because fixed capture-related costs remain sensitive to utilisation (Hersbach et al., 2025; IEAGHG, 2012). Lower-capacity-factor, outage-inclusive and start-stop-rich operating scenarios remain necessary extensions for future work.

TES physical boundary: Charging assumes additional steam-cycle heat diversion, and useful discharge supplies the CCS reboiler in place of contemporaneous live-steam extraction. The 0.28 kWe/kWth factor approximates both electrical effects. Heat delivery at suitable

temperature and pressure is assumed; storage temperature, pressure, heat-exchanger performance and steam-cycle control are not simulated. Auxiliary electricity, time-dependent standing losses and variable O&M are not separately modelled, so their omission does not imply physically zero consumption, losses or cost.

Electrical headroom: The full TES discharge credit requires up to approximately 15.213 MW above the adopted net reference point. All useful-discharge hours coincide with Case 0 output at 630.8 MW. Adding the calculated increment gives approximately 646.01 MW, which is not demonstrated deliverable plant output. The unrestricted result is conditional on sufficient turbine-generator and export capability. The fixed-schedule diagnostic in Section 3.4 examines the consequence of restricting that credit.

Chronological TES dispatch model: The TES calculation is implemented externally in Python using an hourly chronological state-of-charge formulation. The model enforces accepted charging, charging spill under full-tank conditions, useful discharge limited by stored energy, unmet discharge under empty-tank conditions and cyclic annual SOC closure. The hourly resolution captures multi-hour thermal shifting but not sub-hourly transients, ramping interactions or detailed steam-cycle control responses.

Charging-heat availability: The reported 188.56 GWh of annual HOMER excess thermal output is a surplus in its heat balance. TES charging is not constrained against that surplus hour by hour, so the total does not establish available charging supply. Fired-boiler heat is not the source of the credited TES discharge benefit.

Reference rule and vessel duration: The p40/p60 rule and four-hour vessel define the TES reference case. Alternative thresholds and durations from one to 72 hours test dependence on those choices. The lowest MCF among the tested configurations is distinct from the reference case and does not establish a general design optimum. Equal nominal TES and BESS durations do not establish equivalent output or service capability.

TES installed-cost assumption: The £40/kWh-th reference and £25–£60/kWh-th sensitivity range are modelling assumptions informed by storage-cost literature. Differences in storage medium, temperature and integration scope limit direct transfer of those costs to a reboiler-side retrofit. The range does not constitute a vendor quotation or a complete site-specific investment estimate.

TES economic boundary: The headline TES MCF includes annualised installed cost, fixed O&M and accepted-charging opportunity cost, less retained-electricity value during useful discharge. The denominator is electrical-equivalent output inferred from useful heat delivery. Both the numerator and denominator depend on the adopted steam-extraction conversion factor and the electrical-headroom assumption.

BESS modelling boundary: The headline cases retain the HOMER battery and converter operating schedules and AC inverter-output denominators. Their incremental cash flows are reconstructed and reassessed at 8% real over 25 years. These schedules were selected under the original 8% nominal interest and 2% inflation settings and are not re-optimised under the

revised financial basis. Battery and converter cost entries do not establish complete installed-project costs.

The headline BESS cases permit 15–100% SOC and exhibit high cumulative throughput. Equivalent full cycles quantify cumulative energy throughput rather than individual full-depth discharge events. Replacement timing reflects the adopted throughput and calendar-life limits, while progressive capacity fade, efficiency deterioration and cycle-depth-dependent ageing are not explicitly modelled. The separate 20–80% SOC sensitivity uses daily SOC closure and perfect price foresight; its distinct asset and revenue boundary also affects MCF.

BESS non-wholesale revenue adjustment: The adjustment described in Section 3.1.2 excludes the wholesale component of the Modo Energy benchmark, avoiding its direct duplication with modelled electricity trading. Applying the remaining benchmark rate to the full 50 MW rating does not demonstrate that those revenues can be earned alongside the retained dispatch. Service availability, SOC reservation, qualification and market co-optimisation are not represented. The adjustment remains fixed in the uncertainty analysis, and MCF before this adjustment is reported separately.

Market-data boundary: The analysis uses an 8,760-hour representative sequence derived from 2024 GB prices with 29 February omitted. The retained source includes the clock-change settlement periods. Numerical reconstruction of the hourly prices does not resolve the preparation mismatch between prices and prescribed thermal-load fractions. Correcting that alignment could affect TES operation and the relative costs; its effect has not been established. Different market years and network constraints could also change the comparison.

Economic scope: The assessment is limited to the marginal flexibility-cost boundary. Whole-plant LCOE, full project investment returns, CO_2 transport and storage tariffs, carbon-price exposure, capture credits, tax treatment, owner's costs, detailed financing structures and site-specific contracting are outside scope. The study therefore supports screening and break-even interpretation rather than a complete commercial appraisal.

Internal checks and evidence status: Reconciliation of source quantities, storage balances and cash flows assesses numerical consistency within the adopted model. It does not establish the accuracy of the simplified plant representation against measured operation. The methods and supporting numerical evidence are documented in this chapter and Appendices B–F.

These boundaries govern the interpretation of Chapter 4. The comparison evaluates the specified energy-shifting cases on an average incremental net-cost basis. Its conclusions remain conditional on the adopted dispatch, cost and physical assumptions.

4. RESULTS AND DISCUSSION

This chapter presents the techno-economic results for plant-integrated TES and grid-scale BESS as energy-shifting pathways associated with an NGCC plant equipped with post-combustion CCS. Following Chapter 3, marginal cost of flexibility (MCF) is expressed as annual incremental net cost per credited MWh-flex. TES includes the opportunity cost of accepted charging and the electricity value attributed to useful reboiler discharge. The headline BESS cases include reconstructed incremental cash flows and a benchmark-based non-wholesale revenue adjustment.

Case 0 is the no-storage reference simulated in HOMER Pro. Case 1 applies the external chronological TES calculation to the retained Case 0 hourly profiles. Case 2 comprises the retained 100 MWh and 200 MWh BESS schedules, both with 50 MW converters, evaluated using revised cash-flow accounting and AC inverter output. A separate SOC-constrained, price-responsive BESS sensitivity examines a different operating policy and cost scope.

The chapter establishes the baseline, reports TES and BESS operation and costs, and then examines the comparison through sensitivity and uncertainty analysis. The discussion relates the numerical results to the physical mechanisms, operating rules and accounting assumptions of the specified cases.

Consolidated tables and figures present the results. Appendix A retains selected HOMER evidence, while Appendices C–F document supporting operating profiles, assumptions, numerical checks and calculation methods.

4.1 Baseline case results

Case 0 provides the no-storage reference through a generic generator, grid interface, prescribed reboiler thermal demand, recovered generator heat and a backup boiler. The adopted 630.8 MW rating is the net NGCC+CCS reference output reported by Alruwaili et al. (2025, Table 6). The simplified HOMER representation does not separately simulate steam extraction or hourly capture and auxiliary loads.

The retained Case 0 outputs provide the common generation, price and thermal-demand evidence. Its original financial outputs are retained as source results; the BESS comparison reconstructs the incremental cash flows at 8% real over 25 years, as described in Chapter 3. The TES calculation uses the hourly prices and prescribed thermal profile externally.

The hourly-export totals give annual generator output and grid sales of approximately 5,208,963,712 kWh. The model-year capacity factor is 94.3%, calculated as 5,208,963.7125 MWh divided by 630.8 MW × 8,760 h. The original HOMER net present cost is £709.70 million and its reported annual operating cost is £40.26 million. These original financial outputs use 8% nominal interest and 2% inflation; they are distinguished from the revised 8% real incremental-cost calculation.

In Case0, generator output equals grid sales because the simplified electrical representation contains no separately represented auxiliary or compression demand. The published reference from which the 630.8 MW rating was adopted is net of those uses at its reference operating point. Their hourly variation is not explicitly modelled here. The equality must therefore not be interpreted as evidence that auxiliary consumption is physically zero, and the published auxiliary allowance should not be deducted a second time from the adopted net reference.

The 94.3% capacity factor describes the adopted screening scenario rather than a forecast of future GB plant utilisation. Within the configured HOMER system, output varies between approximately 374.8 MW and 630.8 MW under the prescribed thermal demand and grid-price inputs. This simulated profile provides the retained operating basis for the storage comparisons.

Table 4-1: Case 0 no-storage baseline results.

Metric	Value	Interpretation
Generator output	5,208,963,712 kWh/year	Hourly-export total, rounded for display
Grid sales	5,208,963,712 kWh/year	Exported electricity under the net-reference representation
Model-year capacity factor	94.3%	Generator output divided by 630.8 MW × 8,760 h
Original HOMER net present cost	£709,701,100	Original 8% nominal interest and 2% inflation
Original HOMER operating cost	£40,259,940/year	Retained software output
Negative-price hours	233 h	Classification from exported model prices
Zero-price hours	9 h	Classification from exported model prices
Non-positive-price hours	242 h	Negative and zero-price hours combined
Minimum model price	−£60.50/MWh	Exported model-price series
Electricity exported at negative prices	98,792.4541 MWh	Case 0 grid sales in the 233 negative-price hours
Electricity exported at zero prices	3,500.1194 MWh	Case 0 grid sales in the nine zero-price hours
Electricity exported at non-positive prices	102,292.5735 MWh	Combined export; not storage charging energy
Minimum observed generator output	374.8 MW	Retained hourly schedule
Full observed generator output	630.8 MW	Adopted net reference rating

The exported model-price series contains 233 negative-price hours and nine zero-price hours, with a minimum of −£60.50/MWh. Case 0 exports 102,292.5735 MWh during these 242 hours. These quantities use the prices at the precision retained in the HOMER export. The unrounded source-hourly averages contain 235 negative-price hours, no exact zeros and a minimum of −£60.36/MWh, demonstrating the effect of price precision on the classification.

Figure 4-1 shows the discrete generator-output bands associated with the imposed thermal-demand levels. The five half-hour load fractions, from 60% to 100% in ten-percentage-point steps, produce nine hourly levels after averaging adjacent intervals. During part-load operation, recovered heat matches the prescribed demand, so the bands primarily reflect the model inputs. All 1,649 part-load hours occur at prices of £55/MWh or below, while 6,994 of the 7,111 full-output hours occur above £55/MWh. HOMER determines the resulting part-load or full-output operation within this configured system.

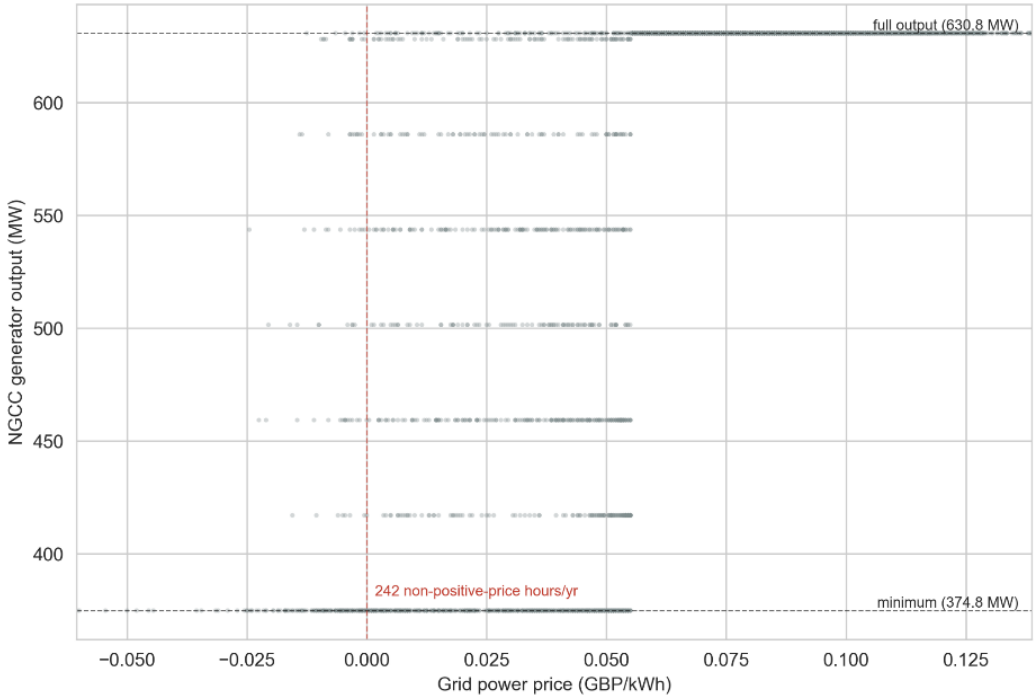


Fig. 4-1: Case 0 generator output against grid price under the prescribed thermal-demand scenario.

The figure provides a model-behaviour check rather than independently identified NGCC operating regimes. The unresolved preparation discrepancy between prices and thermal-load fractions, described in Chapter 3, limits interpretation of their same-hour relationship. The storage results remain conditional on the retained profiles.

Figure 4-2 compares grid-price distributions during boiler idle and boiler firing periods in the Case 0 baseline. The median price during boiler idle periods is approximately GBP 70/MWh, while the median price during boiler firing periods is approximately GBP 96/MWh. Boiler firing therefore coincides with a higher median price environment in the modelled year.

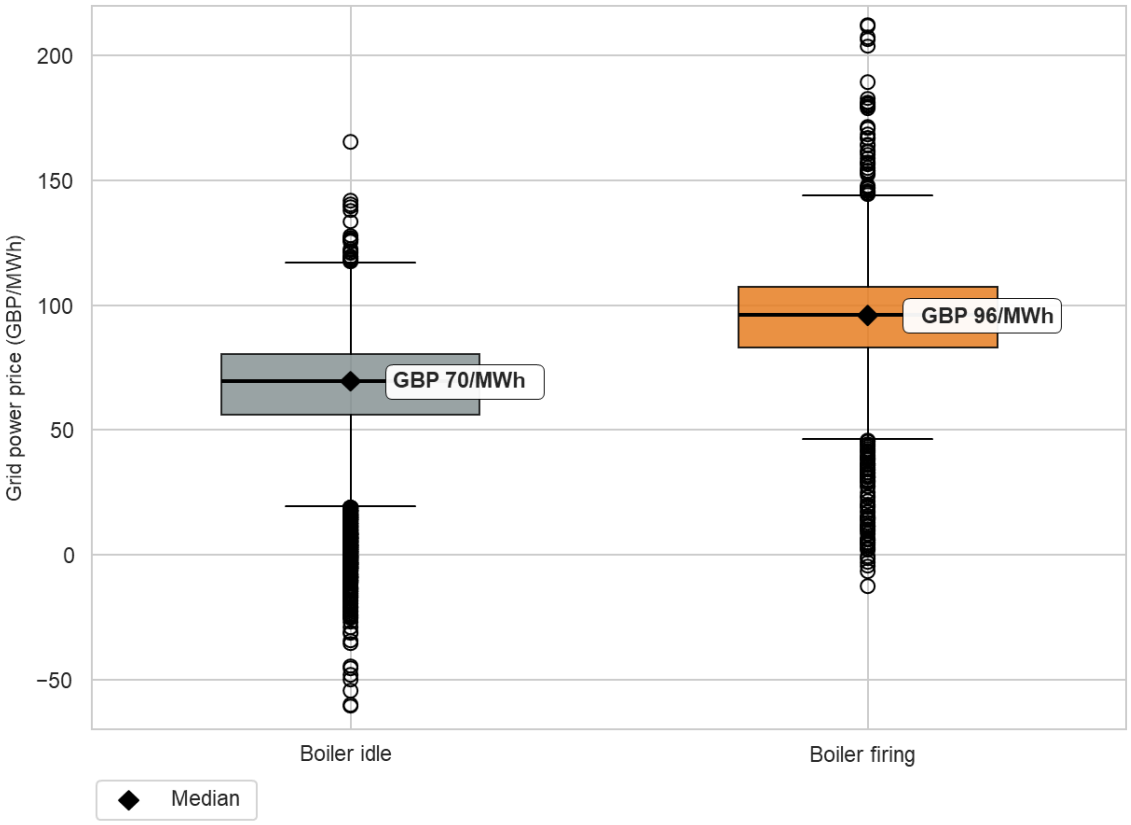


Fig. 4-2: Grid-price distribution during boiler idle and boiler firing periods

Figure 4-2 describes the association between grid prices and boiler operation under the prescribed HOMER thermal profile. The boiler-price relationship does not measure steam extraction or its electrical penalty. Those effects enter the separate TES screening calculation through the assumed charging opportunity cost and useful-discharge electricity credit.

The reported annual excess thermal output is approximately 188.56 GWh-th, equivalent to 9.90% of annual thermal demand. It is surplus within the HOMER heat balance. The TES calculation does not constrain charging against this surplus hourly, so the quantity is not evidence of available TES charging supply. Appendix A distinguishes this thermal balance from the assumed steam-extraction mechanism.

4.2 TES pathway results

The TES pathway represents plant-integrated sensible-hot thermal storage supplying the CCS solvent-regeneration reboiler. Stored heat is discharged only to the reboiler; it does not pass through the turbine and does not generate electricity directly. The electrical-equivalent flexibility arises because useful TES discharge reduces contemporaneous steam extraction for solvent regeneration, allowing additional electrical output to be retained during selected higher-price hours.

The reference calculation applies p40/p60 dispatch thresholds of £69/MWh and £79/MWh, a four-hour vessel, a 20% shift fraction and 90% thermal round-trip efficiency. The vessel has a thermal rate of 54.3308 MW-th and stored-energy capacity of 217.3232 MWh-th. Installed cost is assumed to be £40/kWh-th, giving £8.6929 million. The storage duration, thresholds and cost are reference assumptions examined through the sensitivities in Section 4.5.

Table 4-2: TES chronological reference-case operation and net cost**.**

Metric	Value	Interpretation
Charging / discharging thresholds	p40 / p60; £69 / £79 per MWh	Reference price rule
TES duration / shift fraction	4 h / 0.20	Reference vessel and eligible reboiler-load share
Thermal round-trip efficiency	90%	Equal square-root split between charging and discharging
Maximum thermal charging or discharging rate	54.3308 MW-th	Modelled thermal rate limit
Stored-energy capacity	217.3232 MWh-th	Four-hour capacity and installed-cost basis
Requested charging	138.9646 GWh-th/year	Before chronological vessel constraints
Accepted charging	50.7016 GWh-th/year	Thermal energy accepted at the charging boundary
Charging spill	88.2630 GWh-th/year	Requested less accepted charging
Charging spill share	63.51%	Spill divided by requested charging
Requested TES discharge	171.3077 GWh-th/year	Requested TES contribution to reboiler heat
Useful TES discharge	45.6314 GWh-th/year	Post-loss heat supplied at the reboiler boundary
Unmet TES discharge request	125.6763 GWh-th/year; 73.36%	Requested less useful discharge; not demonstrated unserved CCS heat
Thermal loss	5.0702 GWh-th/year	Accepted charging less useful discharge
Annual useful-discharge benchmark	125.0681 GWh-th/year	Minimum of 90% of requested charging and requested discharge
Retention against annual benchmark	36.49%	Useful discharge divided by the annual benchmark
Equivalent full cycles	221.33/year	Stored-energy cycling intensity
Electrical-equivalent flexibility	12,776.80 MWh-flex/year	Useful discharge × 0.28; conditional electrical credit
Installed TES cost	£8.6929 million	£40/kWh-th × stored-energy capacity
Annualised TES capital cost	£814,342.88/year	8% real over 25 years
Fixed TES O&M	£86,929.28/year	1% of installed cost
Accepted-charging opportunity cost	£788,965.87/year	Foregone electricity valued at charging-hour prices
Useful-discharge electricity value	£1,141,938.60/year	Retained electrical credit valued at discharge-hour prices
Annual incremental net cost	£548,299.43/year	Capital recovery + O&M + charging cost − discharge value
TES MCF	£42.91/MWh-flex	Annual incremental net cost divided by credited MWh-flex

Source: Python post-processing of the Case 0 hourly evidence base using the SOC-constrained TES calculation defined in Section 3.3.3.

Requested charging totals 138.9646 GWh-th, of which 50.7016 GWh-th is accepted. The remaining 88.2630 GWh-th, or 63.51%, is charging spill caused by the finite vessel and the chronology of eligible charging periods. This is rejected charging demand within the TES calculation, rather than measured curtailment of available plant heat.

Useful discharge is 45.6314 GWh-th against a requested TES contribution of 171.3077 GWh-th. The unmet TES discharge request is therefore 125.6763 GWh-th, or 73.36%. This measures the shortfall in the requested TES contribution, not unserved CCS heat demand. Useful discharge is 36.49% of the 125.0681 GWh-th annual benchmark, which removes chronology and vessel-capacity constraints while retaining the dispatch-generated requests and 90% thermal efficiency.

Using the 0.28 kWe/kWth factor, useful discharge corresponds to 12,776.80 MWh-flex/year of retained electrical credit. This conversion assumes that stored heat replaces contemporaneous reboiler steam extraction. Its delivery depends on the thermal and electrical-headroom conditions described in Chapter 3 and examined in Table 4-9.

Annualised capital cost and fixed O&M total £901,272.16/year. Accepted-charging opportunity cost adds £788,965.87/year, while useful-discharge electricity value subtracts £1,141,938.60/year. The resulting annual incremental net cost is £548,299.43, giving TES MCF of £42.91/MWh-flex.

The accepted-charge-weighted electricity price is £55.57/MWh and the useful-discharge-weighted price is £89.38/MWh, a spread of £33.80/MWh. Accounting for 90% thermal round-trip efficiency gives an operating-value margin of £27.63/MWh-flex before annualised capital cost and fixed O&M. This margin describes the credited operating value within the assumed TES boundary.

Table 4-3: Heat-demand multiplier comparison with proportionally resized four-hour TES.

Quantity	Multiplier 1.00	Multiplier 1.10 reference
Peak prescribed reboiler demand (MW-th)	246.9582	271.6540
TES thermal rate (MW-th)	49.3916	54.3308
Stored-energy capacity (MWh-th)	197.5665	217.3232
Accepted charging (GWh-th/year)	46.0923	50.7016
Useful discharge (GWh-th/year)	41.4831	45.6314
Charging spill (GWh-th/year)	80.2391	88.2630
Electrical-equivalent flexibility (MWh-flex/year)	11,615.27	12,776.80
Installed TES cost (£ million)	7.9027	8.6929
TES MCF (£/MWh-flex)	42.91	42.91

The 1.10 multiplier is an assumed elevated-heat-demand scenario. Reducing it to 1.00 while resizing the four-hour vessel proportionally reduces capacity, thermal throughput and credited electricity, but leaves MCF at £42.91/MWh-flex. The unchanged unit cost follows from proportional scaling of the numerator and denominator. It does not establish the response of a fixed installation to a change in heat demand.

Figure 4-3 presents a representative week from the SOC-constrained TES reference case. The three panels connect the p40/p60 price rule to accepted charging, useful reboiler-side discharge, charging spill and vessel SOC. The profile makes the finite-vessel mechanism visible: low-price charging requests cannot always be accepted when the vessel is full, while high-price discharge is limited when stored energy has been depleted.

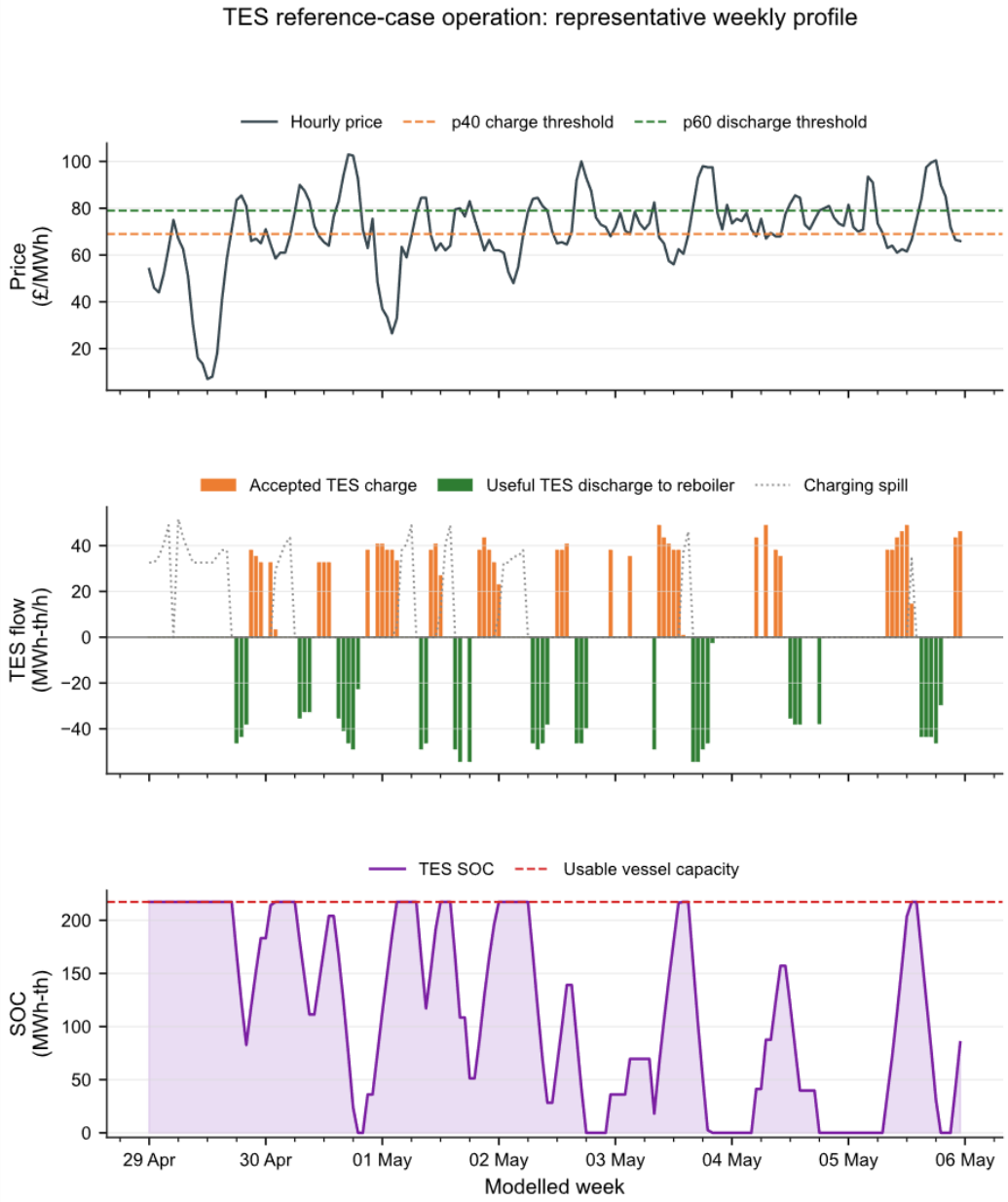


Fig. 4-3: Representative weekly TES operating profile under the p40/p60 reference rule

During the representative week, accepted charging occurs primarily below p40 and useful reboiler-side discharge primarily above p60. Charging spill appears where further low-price charging opportunities occur while the vessel is already full or close to its upper limit. The SOC trace repeatedly reaches both vessel boundaries, illustrating why a chronological calculation is required.

Figure 4-4 extends the same interpretation across the modelled year by presenting daily mean price, accepted TES charging, useful reboiler-side discharge and the daily SOC range. The annual view shows how the 4 h reference vessel repeatedly interacts with its usable capacity limits under the p40/p60 rule.

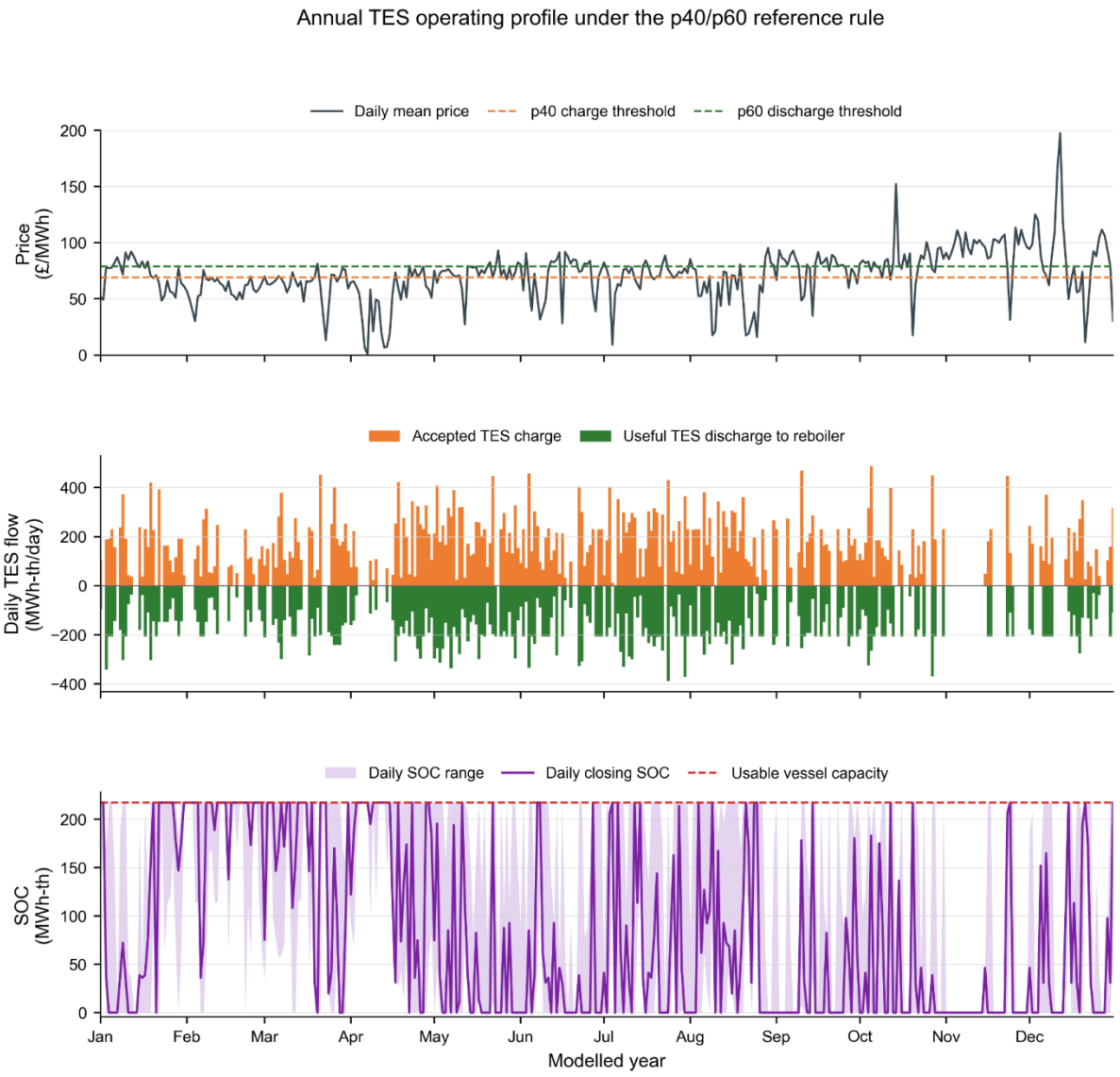


Fig. 4-4: Annual TES operating profile under the p40/p60 reference rule.

The annual profile shows repeated transitions between near-empty and near-full states. Appendix C reports the corresponding SOC carpet plot and occupancy summary: the vessel is within 1% of empty for 39.1% of modelled hours and within 1% of full for 31.9%. These patterns describe the four-hour TES reference case operated under the p40/p60 dispatch rule. The storage duration and dispatch thresholds are reference assumptions; their effects are examined separately through sensitivity analysis.

The weekly and annual profiles describe the chronological operation underlying the TES net-cost result. Section 4.3 presents the retained BESS schedules and the separate SOC-constrained sensitivity, before the specified cases are compared in Section 4.4.

4.3 BESS pathway results

The BESS pathway stores electricity and returns it through the AC converter interface. The headline results retain the HOMER operating schedules and annual inverter output, with the incremental cash flows reconstructed at 8% real over 25 years. Annual AC output is the credited MWh-flex denominator.

The 100 MWh configuration had the lowest original system NPC among the 100, 200 and 400 MWh capacities tested at a fixed 50 MW converter rating. The 200 MWh case is retained as an energy-capacity sensitivity at the same converter power. These schedules were not re-optimised under the revised 8% real financial basis.

Both cases use £165/kWh of nominal battery capacity for initial capital and replacement on the adopted 2025 cost-scenario basis. Converter capital is separate at £300/kW, or £15 million per case, giving initial battery-plus-converter costs of £31.5 million and £48 million. A complete site-specific balance-of-plant and grid-connection cost estimate is not available. Chapter 3 defines the external fixed O&M and benchmark-based non-wholesale revenue treatment.

Table 4-4 separates the original HOMER NPC evidence from the revised incremental present costs used in the comparison. Fractional-year battery replacements, converter replacement and year-25 salvage are included in the reconstructed cash flows. The annual non-wholesale adjustment is £1,716,440.33 for each 50 MW case.

Table 4-4: BESS operation and revised financial results.

Metric	BESS-100	BESS-200	Unit or basis
Nominal battery capacity	100	200	MWh
Converter rating	50	50	MW
Battery initial / replacement unit cost	165	165	£/kWh of nominal capacity; 2025 scenario
Initial battery plus converter cost	31.50	48.00	£ million; converter separate from battery unit cost
Battery round-trip efficiency input	90	90	%
Rectifier / inverter efficiency inputs	95 / 95	95 / 95	% in each direction
Combined conversion efficiency input	81.225	81.225	% = 90% × 95% × 95%
Annual battery throughput	191,882.1	197,924.9	MWh/year
Annual equivalent full cycles	1,918.82	989.62	Throughput divided by nominal capacity
Battery replacement interval	3.126920	6.062905	Years; fractional timing retained
Original HOMER system NPC	844,326,600	851,555,700	£; original financial settings
Original Case 0 system NPC	709,701,100	709,701,100	£; original financial settings

Metric	BESS-100	BESS-200	Unit or basis
Original HOMER incremental NPC	134,625,500	141,854,600	£; provenance only
Revised incremental present cost	116,087,816.88	124,304,689.24	£; reconstructed at 8% real
Annualised revised incremental cost	10,874,964.95	11,644,711.52	£/year
External fixed O&M	250,000.00	250,000.00	£/year
Annual cost before non-wholesale adjustment	11,124,964.95	11,894,711.52	£/year
Non-wholesale revenue adjustment	1,716,440.33	1,716,440.33	£/year
Annual incremental net cost	9,408,524.62	10,178,271.19	£/year
Annual AC output / MWh-flex	172,925.53	174,019.50	MWh-flex/year
Achieved annual AC energy-return ratio	81.221	79.240	%; includes excess-energy effects
Annual excess electricity	8.48	4,589.65	MWh; not an additional assumed efficiency loss
MCF before non-wholesale adjustment	64.33	68.35	£/MWh-flex
Headline BESS MCF	54.41	58.49	£/MWh-flex

For BESS-100, the revised incremental present cost is £116.09 million. Annualisation gives £10.875 million/year; adding £0.250 million/year fixed O&M and subtracting £1.716 million/year non-wholesale revenue gives £9.409 million/year. Dividing by 172,925.53 MWh-flex/year gives £54.41/MWh-flex.

For BESS-200, the revised incremental present cost is £124.30 million and annual incremental net cost is £10.178 million/year. AC output is 174,019.50 MWh-flex/year, giving £58.49/MWh-flex. The larger energy capacity therefore raises the net cost more than the credited annual output in these retained cases.

Table 4-5: Battery and converter replacement schedules over the 25-year comparison.

Case / component	Replacement years	Financial treatment
Headline BESS-100 battery	3.13; 6.25; 9.38; 12.51; 15.63; 18.76; 21.89	Fractional-year cash flows and year-25 salvage included
Headline BESS-200 battery	6.06; 12.13; 18.19; 24.25	Fractional-year cash flows and year-25 salvage included
Both headline converters	15	Replacement and year-25 residual-life salvage included
Separate SOC sensitivity: both batteries	10; 20	Calendar-limited replacements; separate battery-only scope, no salvage

The retained battery throughputs correspond to 1,918.82 and 989.62 EFC/year for BESS-100 and BESS-200. EFC measures cumulative throughput relative to nominal capacity rather than

the number of individual full-depth discharge events. The assumed 6,000 EFC life and ten-year calendar limit produce replacement intervals of 3.13 and 6.06 years. Table 4-5 shows the replacement timing already included in the revised costs.

BESS-100 operates at approximately 5.26 EFC/day and is retained as a high-throughput screening case. Progressive capacity fade, efficiency deterioration and cycle-depth-dependent ageing are not explicitly modelled. The supplementary sensitivity in Table 4-6 examines a 20–80% SOC policy with daily SOC recovery and price-responsive dispatch under a separately stated financial boundary.

Figure 4-5 presents the retained 100 MWh BESS operating profile. Daily charging, AC export and SOC show the high-throughput schedule associated with the replacement interval reported in Table 4-4. The original lowest-NPC selection was limited to the capacities tested in HOMER.

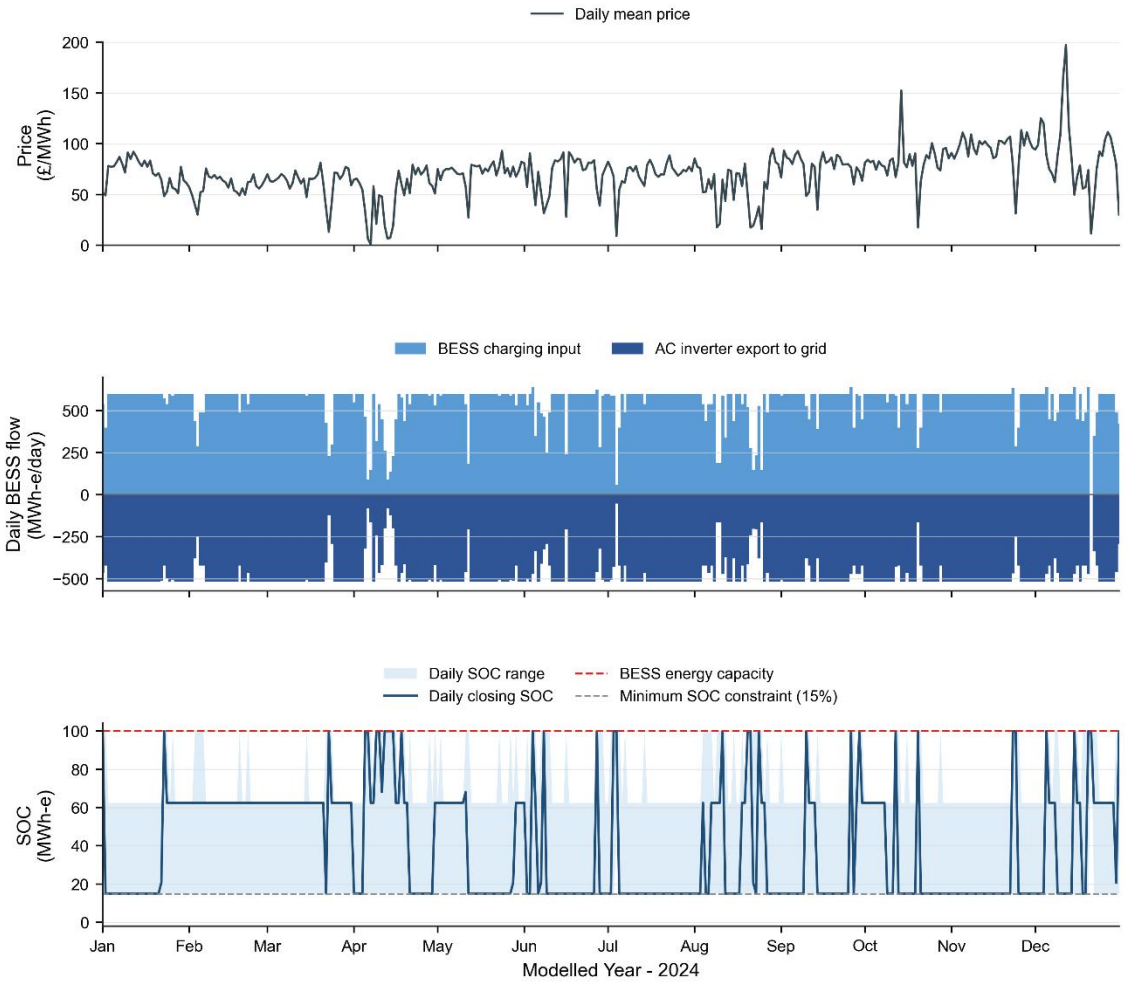


Fig. 4-5: Annual operating profile of BESS-100, the lowest-NPC configuration among the capacities tested in HOMER.

Both headline cases use a 15–100% SOC window, a 90% battery round-trip efficiency and 95% converter efficiency in each direction. The combined conversion input is 81.225%. Achieved annual AC energy-return ratios are 81.221% for BESS-100 and 79.240% for BESS-200. The latter also records 4,589.65 MWh of excess electricity, compared with 8.48 MWh for BESS-100; these output ratios therefore include excess-energy effects as well as conversion losses.

Increasing nominal battery capacity reduces relative cycling intensity and extends the replacement interval, but annual AC output changes only from 172,925.53 to 174,019.50 MWh-flex. At the unchanged 50 MW converter rating and retained operating schedules, this additional output does not offset the higher annual incremental net cost.

Table 4-6: SOC-constrained, price-responsive BESS sensitivity.

Quantity	**100 MWh / 50 MW**	**200 MWh / 50 MW**
SOC operating window	20–80%	20–80%
Daily initial and terminal SOC	50%	50%
AC round-trip efficiency	81.22%	81.22%
Annual AC charging (MWh/year)	45,437.16	76,417.89
Annual AC export (MWh-flex/year)	36,904.06	62,066.61
Realised EFC per day	1.122	0.943
Realised EFC per year	409.49	344.35
Annualised battery asset cost (£/year)	2,593,285.09	5,186,570.19
Fixed O&M (£/year)	250,000.00	250,000.00
Charging cost (£/year)	2,059,057.14	3,653,553.02
Discharge electricity value (£/year)	3,052,359.80	5,375,664.90
Annual incremental net cost (£/year)	1,849,982.43	3,714,458.31
Sensitivity MCF (£/MWh-flex)	50.13	59.85
Battery replacement years	10 and 20	10 and 20
Converter capex / salvage / non-wholesale revenue	Excluded	Excluded

The separate sensitivity uses perfect price foresight within each 24-hour model block, a 20–80% SOC window, 50% initial and terminal SOC, and mutually exclusive charging and discharging. It realises 1.122 and 0.943 EFC/day, exporting 36,904.06 and 62,066.61 MWh-flex/year. MCF is £50.13/MWh-flex for 100 MWh and £59.85/MWh-flex for 200 MWh. Its battery-only capital scope excludes converter capital, salvage and non-wholesale revenue, so the differences from the headline results cannot be attributed solely to the SOC policy.

Table 4-7 separates BESS MCF before and after the non-wholesale revenue adjustment. The completed-2024 benchmark reported by Jennings (2025a) is applied at £34,328.81/MW-year to the full 50 MW converter rating. Wholesale revenue is excluded from this adjustment because the retained grid cash flows already account for electricity purchases and sales.

Table 4-7: BESS MCF before and after the benchmark-based non-wholesale revenue adjustment.

Case	Before adjustment (£/MWh-flex)	After adjustment (£/MWh-flex)	Reduction (£/MWh-flex)
BESS-100	64.33	54.41	9.93
BESS-200	68.35	58.49	9.86

Figure 4-6 shows the effect of the common £1.716 million/year non-wholesale adjustment on the two BESS cases.

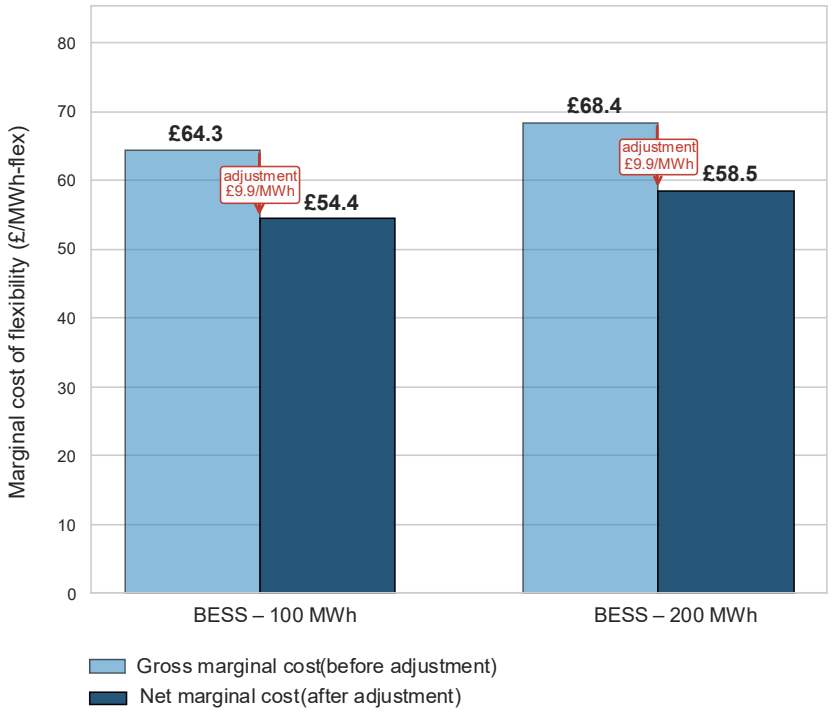


Fig. 4-6: BESS marginal cost of flexibility before and after the benchmark-based non-wholesale revenue adjustment.

The adjustment reduces MCF by £9.93/MWh-flex for BESS-100 and £9.86/MWh-flex for BESS-200. It is a full-nameplate screening allowance based on an observed market benchmark. Availability and SOC commitments for simultaneous services are not co-optimised, so the adjustment is not a forecast of case-specific attainable revenue.

BESS-100 is the lower-cost headline electrical-storage case at £54.41/MWh-flex, compared with £58.49/MWh-flex for BESS-200. These retained-schedule results form the BESS comparators in Section 4.4. The SOC sensitivity remains a separate operating and accounting case.

4.4 Central cost comparison

The central comparison uses annual incremental net cost per credited MWh-flex under the boundaries defined in Chapter 3. TES includes capital recovery, fixed O&M, accepted-charging opportunity cost and useful-discharge electricity value. BESS includes revised incremental plant-plus-storage cash flows, external fixed O&M and the non-wholesale revenue adjustment. The quantities describe specified energy-shifting cases with different physical functions and dispatch rules.

The four-hour p40/p60 TES reference has annual incremental net cost of £548,299.43 and credited flexibility of 12,776.80 MWh-flex, giving £42.91/MWh-flex. The corresponding BESS headline costs are £54.41/MWh-flex for 100 MWh and £58.49/MWh-flex for 200 MWh.

Figure 4-7 and Table 4-8 present the reference-case comparison. TES has the lower MCF under these assumptions, with TES/BESS ratios of 0.789 for BESS-100 and 0.734 for BESS-200.

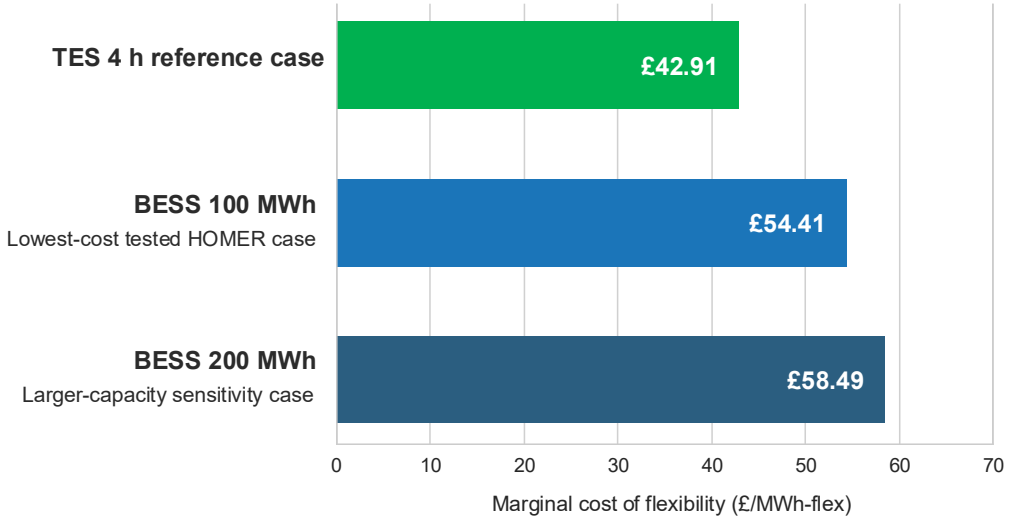


Fig. 4-7: Reference-case MCF for four-hour TES and retained BESS configurations.

Table 4-8: Reference-case marginal cost comparison.

Case	Annual incremental net cost (£/year)	Credited output (MWh-flex/year)	MCF (£/MWh-flex)	TES / BESS MCF ratio
TES four-hour reference	548,299.43	12,776.80	42.91	—
BESS-100	9,408,524.62	172,925.53	54.41	0.789
BESS-200	10,178,271.19	174,019.50	58.49	0.734

The cost difference combines technology, equipment size, dispatch and accounting effects. The existing cases do not quantify how much of the difference is attributable to dispatch alone. Including accepted-charging opportunity cost and useful-discharge electricity value changes the TES cost calculation without changing its reference thermal schedule. The threshold

analysis in Section 4.5.1 isolates changes within the TES rule set, rather than the dispatch contribution to the TES–BESS difference.

TES credits 12,776.80 MWh-flex/year through avoided contemporaneous steam extraction, whereas the BESS cases return approximately 173,000–174,000 MWh/year at the AC interface. These energy quantities permit cost reporting in common units, but do not establish equivalent power availability, frequency-response provision or substitutable grid services.

The retained Case 0 generator is already at 630.8 MW in all 1,075 useful TES discharge hours. Adding the full external electricity credit gives a maximum of approximately 646.01 MW. This is a calculated screening quantity; additional turbine-generator and export capability has not been established. Table 4-9 reports the fixed-schedule diagnostic under illustrative additional-headroom limits.

The diagnostic keeps the reference thermal schedule, charging opportunity cost and asset costs unchanged, while restricting credited discharge electricity and its associated value. The headroom limit is defined above the adopted 630.8 MW net reference. No alternative dispatch schedule is optimised.

Table 4-9: Fixed-schedule TES electrical-credit diagnostic under illustrative additional-headroom limits.

Additional headroom (MW)	Credited MWh-flex/year	Credit retained (%)	Annual incremental net cost (£/year)	TES MCF (£/MWh-flex)
0.000	0.00	0.00	1,690,238.03	Undefined
5.000	5,219.67	40.85	1,223,827.24	234.46
10.000	10,027.12	78.48	795,215.61	79.31
15.213	12,776.80	100.00	548,299.43	42.91

At 10 MW additional headroom, credited TES flexibility falls to 10,027.12 MWh-flex/year and MCF rises to £79.31/MWh-flex, above both headline BESS values. At 5 MW, MCF is £234.46/MWh-flex. With no additional headroom, credited flexibility is zero and MCF is undefined. These cases demonstrate that headroom can reverse the reference ordering, without determining the actual limit of the plant.

The £42.91/MWh-flex TES result is therefore conditional on sufficient headroom and the assumed delivery of useful heat to the reboiler. Other material limitations include the prescribed load profile, unresolved price–thermal alignment, unequal dispatch rules and different cost and revenue scopes. Their combined effect on the comparison is not quantified.

The following sensitivities examine how the specified cost relationship changes with TES operating assumptions and economic inputs. Cost parity denotes equal MCF for the selected cases; it does not identify interchangeable technical capabilities or forecast future technology costs.

4.5 Sensitivity and uncertainty results

The sensitivity analysis examines TES thresholds, prescribed reboiler-load shape, storage duration, individual technical and economic parameters, joint cost-parity conditions and illustrative Monte Carlo scenarios. All results use the TES net-cost definition in Section 3.3 and the revised headline BESS cash flows.

The p40/p60 rule and four-hour vessel remain the reference assumptions. Other thresholds and durations are sensitivity cases. The analysis evaluates dependence on these choices without establishing a globally optimal design or sampling the unresolved plant-headroom and price–thermal alignment uncertainties.

4.5.1 TES dispatch-threshold sensitivity

The threshold sweep combines charging percentiles p10–p50 with discharging percentiles p50–p90, giving 25 cases for the same four-hour TES vessel. Table 4-10 reports all MCF values and the thermal-flow results for five symmetric combinations. More selective price windows reduce the number of eligible charging and discharging opportunities.

The p40/p60 reference gives £42.91/MWh-flex and 12,776.80 MWh-flex/year. The lowest MCF among the tested combinations is £29.76/MWh-flex at p50/p50, with 18,590.19 MWh-flex/year. At the shared p50 price of £74/MWh, the 75 exactly tied hours trigger neither charging nor discharging. The p50/p50 sensitivity therefore preserves mutually exclusive actions.

Table 4-10: TES threshold sensitivity. Panel A reports MCF (£/MWh-flex) for all 25 combinations; Panel B reports selected symmetric cases.

Charging percentile / discharging percentile	**p50**	**p60**	**p70**	**p80**	**p90**
p10	172.35	191.58	218.59	262.28	401.89
p20	84.13	97.97	124.44	169.10	285.66
p30	50.19	60.44	81.04	119.85	232.29
p40	36.07	42.91	57.89	87.87	191.51
p50	29.76	33.86	45.56	69.22	156.34
Panel B: symmetric case	**Accepted charging (GWh-th/year)**	**Charging spill (GWh-th/year)**	**Useful discharge (GWh-th/year)**	**MWh-flex/year**	**MCF (£/MWh-flex)**
p10/p90	7.2728	25.8771	6.5455	1,832.75	401.89
p20/p80	15.5793	51.2014	14.0214	3,925.98	169.10
p30/p70	29.0421	73.5887	26.1379	7,318.62	81.04
p40/p60	50.7016	88.2630	45.6314	12,776.80	42.91
p50/p50	73.7706	98.9823	66.3936	18,590.19	29.76

Across the symmetric cases, less selective windows increase useful output and spread annual asset cost over more MWh-flex. Absolute charging spill alone does not measure utilisation,

because requested charging also changes. The following load-shape sensitivity examines a different source of dependence and does not reconstruct the unresolved preparation alignment.

4.5.2 Reboiler-load-shape sensitivity

The retained prescribed reboiler-load profile determines the thermal requests entering the TES calculation. The load-shape sensitivity compares that profile with two alternatives while leaving the representative model-price sequence unchanged. It examines dependence on the selected demand shape rather than correcting the price–thermal preparation discrepancy.

The three cases use p40/p60 dispatch, four-hour duration, a 20% shift fraction, 90% thermal round-trip efficiency and £40/kWh-th installed cost. The flat case applies the same annual mean demand in every hour. The inverse-rank case reverses demand against price ranking while retaining the annual demand distribution. Capacity is recalculated from each case's peak demand, so the flat case also reduces vessel capacity from 217.3232 to 173.8685 MWh-th.

The flat case gives 41.01 GWh-th/year useful discharge, 11,483.91 MWh-flex/year and MCF of £37.10/MWh-flex. The inverse-rank case gives 44.95 GWh-th/year, 12,586.66 MWh-flex/year and £45.45/MWh-flex. The lower flat-case MCF reflects both changed thermal operation and the smaller vessel cost, rather than a change in demand timing alone.

TES has lower MCF than both headline BESS cases in these three prescribed scenarios. The comparison remains conditional: flat and inverse demand profiles do not establish what a consistently corrected price–thermal alignment would produce for either storage pathway.

Table 4-11: Prescribed reboiler-load-shape sensitivity.

Prescribed load shape	Useful discharge (GWh-th/year)	MWh-flex/year	Spill (%)	Retention (%)	TES MCF (£/MWh-flex)	Parity cost vs BESS-100 (£/kWh-th)
Reference profile	45.63	12,776.80	63.51	36.49	42.91	46.52
Flat same-mean demand	41.01	11,483.91	70.58	29.42	37.10	51.03
Inverse-rank same-distribution demand	44.95	12,586.66	72.63	35.43	45.45	45.00

Spill is rejected charging divided by requested charging. Retention is useful discharge divided by the minimum of efficiency-adjusted requested charging and requested discharge. These denominators differ: the inverse-rank values of 72.63% and 35.43% therefore need not sum to 100%. The flat case also uses a smaller proportionally sized vessel.

4.5.3 TES storage-duration sensitivity

The storage-duration sensitivity evaluates 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 hours at the reference thermal rate and p40/p60 rule. Longer duration increases stored-energy capacity and useful discharge, but also increases installed cost. Table 4-12 reports all ten tested durations using the same net-cost accounting.

The two-hour case has the lowest MCF among the tested durations, at £31.94/MWh-flex and 8,397.73 MWh-flex/year. The one-hour result is £32.31/MWh-flex, while the four-hour reference remains £42.91/MWh-flex with 12,776.80 MWh-flex/year. These are discrete sensitivity results; the two-hour case does not replace the reference.

Table 4-12: TES storage-duration sensitivity from 1 to 72 hours.

Duration (h)	Capacity (MWh-th)	Useful discharge (GWh-th/year)	MWh-flex/year	TES MCF (£/MWh-flex)
1	54.3308	16.6666	4,666.66	32.31
2	108.6616	29.9919	8,397.73	31.94
3	162.9924	39.2510	10,990.27	36.19
4	217.3232	45.6314	12,776.80	42.91
6	325.9848	53.5778	15,001.77	60.47
8	434.6464	58.3258	16,331.22	79.23
12	651.9696	63.9751	17,913.04	117.78
24	1,303.9392	72.3044	20,245.22	231.56
48	2,607.8784	77.8940	21,810.32	459.28
72	3,911.8176	80.3680	22,503.05	684.01

At 48 and 72 hours, useful electrical-equivalent output is 21,810.32 and 22,503.05 MWh-flex/year, while MCF reaches £459.28 and £684.01/MWh-flex. Beyond the two-hour minimum in this sweep, vessel cost increases more rapidly than the useful-output benefit under the retained operating rule.

4.5.4 One-at-a-time sensitivity analysis

The one-at-a-time analysis varies TES installed cost, the common charging/discharging conversion factor, TES shift fraction, the BESS incremental-NPC multiplier and real discount rate. Other inputs remain at their reference values. Changes in discount rate re-discount the BESS replacement and salvage cash flows as well as changing capital recovery.

Figure 4-8 shows the affected-pathway MCF response. TES installed cost and the thermal-to-electrical conversion factor produce the largest TES ranges among the tested variations. The BESS multiplier changes aggregate incremental present cost, while the discount rate affects

both pathways. The unchanged TES shift-fraction result follows from proportional scaling in the formulation.

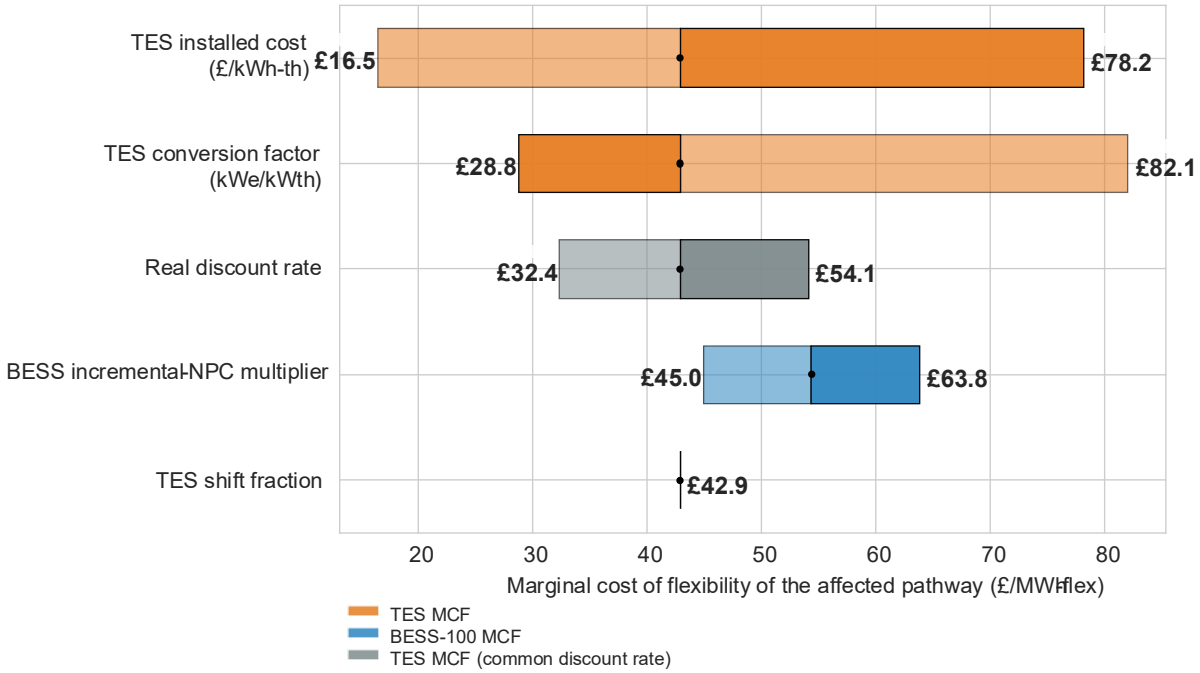


Fig. 4-8: One-at-a-time MCF sensitivity to selected input parameters.

Table 4-13: One-at-a-time sensitivity results.

Parameter / low–high inputs	Affected case	MCF at low input (£/MWh-flex)	MCF at high input (£/MWh-flex)
TES cost: £25–60/kWh-th	TES	16.46	78.18
Both conversion factors: 0.18–0.35 kWe/kWth	TES	82.10	28.81
TES shift fraction: 0.10–0.30	TES	42.91	42.91
BESS NPC multiplier: 0.85–1.15	BESS-100	44.97	63.84
BESS NPC multiplier: 0.85–1.15	BESS-200	48.45	68.53
Real discount rate: 6–10%	TES	32.40	54.13
Real discount rate: 6–10%	BESS-100	51.89	57.00
Real discount rate: 6–10%	BESS-200	54.84	62.25

Varying the shift fraction from 0.10 to 0.30 leaves MCF unchanged because vessel capacity, thermal flows, annual costs and credited output scale together. This is an identity of the proportional formulation, not independent evidence of economic insensitivity. Fixed equipment size, fixed electrical headroom or non-proportional costs could break the relationship; zero credited output would make MCF undefined.

4.5.5 TES CAPEX × BESS NPC parity mapping

The parity map varies TES installed cost from £25 to £60/kWh-th and the BESS incremental-NPC multiplier from 0.60 to 1.40. It is an algebraic sensitivity based on fixed reference schedules and annual outputs. The BESS multiplier scales aggregate incremental present cost, including embedded grid cash flows, while external O&M and the non-wholesale adjustment remain fixed. It is not a battery-capital-cost multiplier.

Figure 4-9 reports the TES/BESS-100 MCF ratio, with values below one indicating lower TES MCF. At a BESS multiplier of 1.00, equal MCF occurs at TES installed costs of £46.52/kWh-th against BESS-100 and £48.83/kWh-th against BESS-200. The £40/kWh-th reference is below both thresholds.

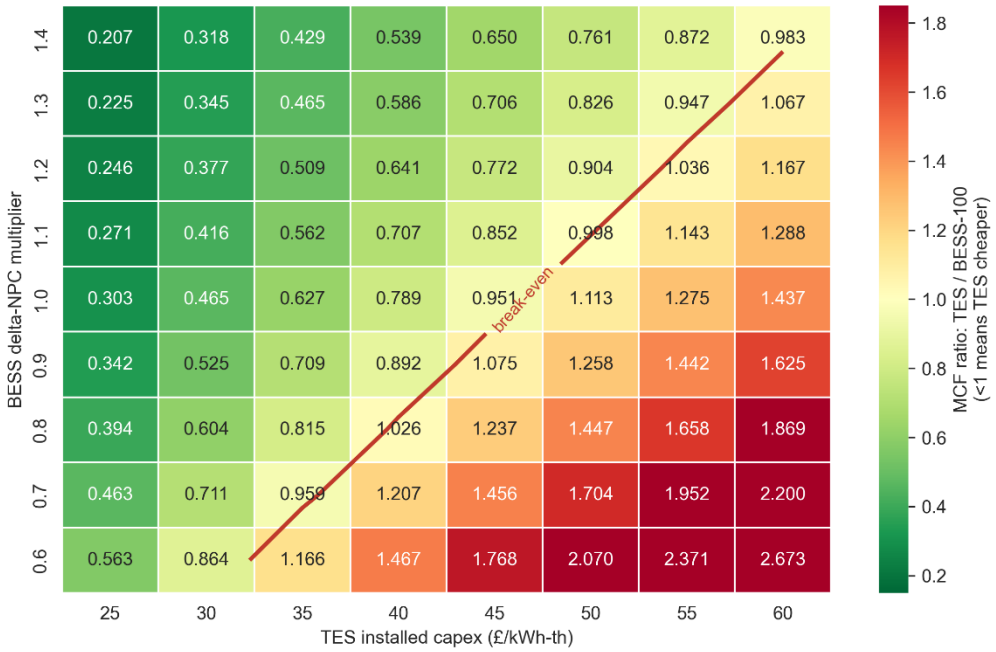


Fig. 4-9: Algebraic sensitivity of the TES/BESS-100 MCF ratio to TES installed cost and the aggregate BESS incremental-NPC multiplier.

Table 4-14: TES installed cost at equal MCF for selected BESS cost assumptions.

BESS cost assumption	Parity vs BESS-100 (£/kWh-th)	Parity vs BESS-200 (£/kWh-th)
Incremental-NPC multiplier 1.00	46.52	48.83
Incremental-NPC multiplier 0.80	39.39	41.24
Incremental-NPC multiplier 0.60	32.25	33.65

The parity thresholds describe combinations of cost assumptions at which the selected cases have equal MCF. Lower TES cost reduces its MCF, while lower BESS incremental cost reduces the TES installed cost at parity. The map identifies cost-parity conditions without predicting the direction or timing of future technology costs.

4.5.6 Monte Carlo uncertainty analysis

The Monte Carlo analysis evaluates 10,000 illustrative scenarios. TES installed cost, the common thermal-to-electrical conversion factor and the BESS incremental-NPC multiplier follow the distributions specified in Chapter 3, with a common real discount rate sampled from 6–10%. The annual non-wholesale adjustment and external fixed O&M remain fixed. Reference dispatch schedules are retained, and BESS replacement and salvage cash flows are re-discounted in each scenario.

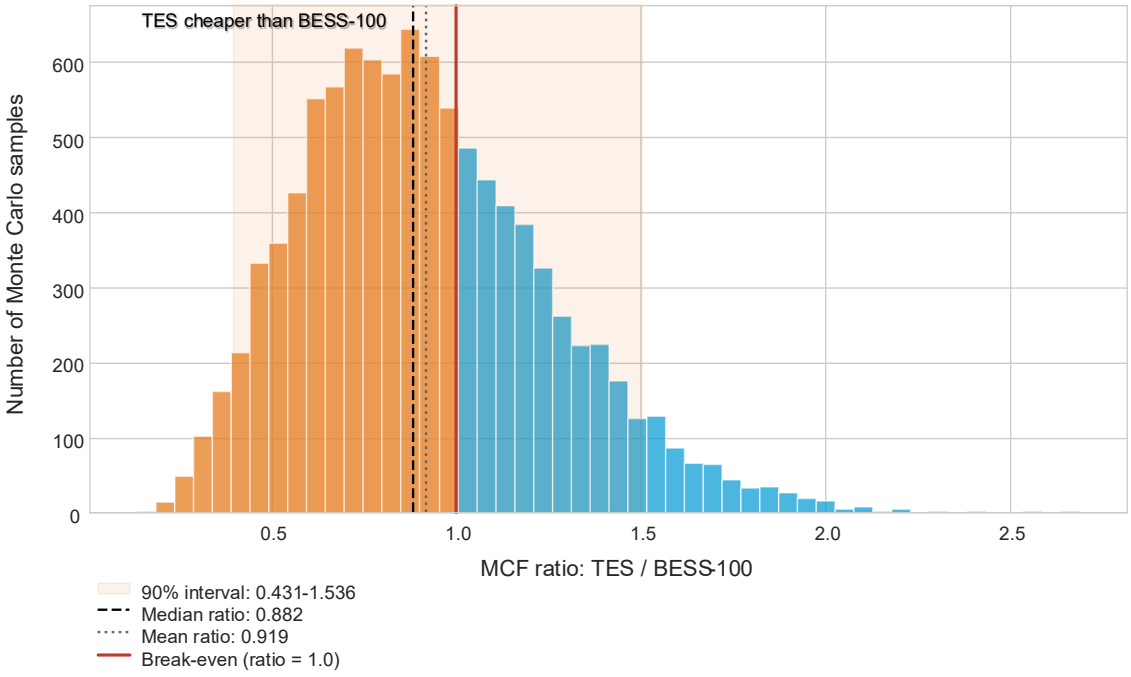


Fig. 4-10: Distribution of the TES/BESS-100 MCF ratio across 10,000 illustrative input scenarios.

TES mean MCF is £49.95/MWh-flex, with a 5th–95th percentile range of £23.33–83.73/MWh-flex. The corresponding BESS-100 mean is £54.44/MWh-flex. The TES/BESS-100 ratio has a mean of 0.919, median of 0.882 and 5th–95th percentile range of 0.431–1.536. Figure 4-10 displays this ratio distribution.

Table 4-15: Monte Carlo results under the illustrative input distributions.

Metric	Result
Number of scenarios	10,000
Scenarios with TES MCF below BESS-100	6,356 / 10,000 (63.56%)
Scenarios with TES MCF below BESS-200	7,075 / 10,000 (70.75%)
TES mean MCF	£49.95/MWh-flex
TES MCF 5th–95th percentile	£23.33–83.73/MWh-flex
BESS-100 mean MCF	£54.44/MWh-flex

Metric	Result
BESS-100 MCF 5th–95th percentile	£47.52–61.28/MWh-flex
BESS-200 mean MCF	£58.53/MWh-flex
BESS-200 MCF 5th–95th percentile	£50.81–66.22/MWh-flex
TES/BESS-100 ratio mean	0.919
TES/BESS-100 ratio median	0.882
TES/BESS-100 ratio 5th–95th percentile	0.431–1.536

TES has lower MCF in 63.56% of scenarios against BESS-100 and 70.75% against BESS-200. These fractions are conditional on the illustrative distributions and assumed independence of the sampled inputs. They are not empirical probabilities that a TES retrofit will outperform BESS.

The sampled ranges describe the chosen economic and conversion-factor uncertainties. They exclude unresolved headroom, heat-delivery and price–thermal alignment effects, and do not substitute the separate SOC-constrained BESS sensitivity for the headline cases. The results therefore complement the cost-parity analysis while retaining the model-boundary limitations.

4.6 Internal consistency checks

The numerical discrepancies reported in Appendix E were below the stated checking tolerances. These results support the numerical consistency of the calculations under the adopted model boundaries and assumptions.

Reconciliation of exported quantities with post-processing does not establish correct upstream price–thermal alignment or plant-model accuracy. The study has no operating-plant measurements against which to establish the physical performance of the integrated TES configuration.

4.7 Discussion and chapter synthesis

Under the specified reference assumptions, four-hour TES operated with p40/p60 thresholds gives £42.91/MWh-flex, compared with £54.41/MWh-flex for BESS-100 and £58.49/MWh-flex for BESS-200. This is a conditional cost comparison of the retained cases rather than an isolated technology advantage.

The chronological TES calculation accepts 50.7016 GWh-th/year of charging and supplies 45.6314 GWh-th/year of useful reboiler heat, equivalent to 12,776.80 MWh-flex/year under the adopted conversion. Charging spill is 88.2630 GWh-th/year and unmet TES discharge requests total 125.6763 GWh-th/year. These quantities show how chronology and finite capacity restrict the requested thermal contribution.

The physical interpretation remains consequential. TES attributes retained electricity to replacing reboiler steam extraction, while BESS returns stored electricity at the AC interface.

The fixed-schedule headroom diagnostic raises TES MCF to £79.31/MWh-flex at 10 MW, reversing the reference ordering. Available plant headroom and heat-delivery conditions therefore remain material qualifications of the TES result.

At the reference BESS cost assumptions, TES reaches equal MCF at installed costs of £46.52/kWh-th against BESS-100 and £48.83/kWh-th against BESS-200. These thresholds describe cost-parity conditions for the selected cases; they do not forecast future TES or BESS prices.

The two-hour TES case has the lowest MCF among the tested durations, giving £31.94/MWh-flex, while four hours remains the reference. The p50/p50 threshold case gives the lowest MCF among the 25 combinations at £29.76/MWh-flex; p40/p60 remains the reference rule. Flat and inverse prescribed demand profiles give £37.10 and £45.45/MWh-flex. These results describe sensitivity to model choices and do not resolve the upstream alignment discrepancy.

TES has lower MCF than BESS-100 and BESS-200 in 63.56% and 70.75% of the illustrative Monte Carlo scenarios. The separate SOC-constrained BESS sensitivity gives £50.13 and £59.85/MWh-flex, with a different operating and cost scope. Neither analysis isolates all differences between the technologies or establishes performance beyond the stated boundaries.

Table 4-16: Chapter 4 result synthesis.

Result area	Finding	Interpretation
Case 0	5,208,963,712 kWh/year generator output; 94.3% capacity factor	Retained representative-year scenario using a net reference rating
TES thermal operation	45.6314 GWh-th/year useful discharge; 125.6763 GWh-th/year unmet TES requests	Chronological vessel constraints restrict the TES contribution
Reference TES and BESS costs	TES £42.91; BESS-100 £54.41; BESS-200 £58.49 per MWh-flex	Conditional net-cost comparison of specified cases
Electrical headroom	10 MW diagnostic: TES £79.31/MWh-flex	Illustrative restriction reverses the reference ordering; actual limit unverified
BESS SOC sensitivity	100 MWh £50.13; 200 MWh £59.85 per MWh-flex	Separate 20–80% SOC, daily recovery and battery-only cost scope
TES installed-cost parity	£46.52/kWh-th vs BESS-100; £48.83/kWh-th vs BESS-200	Equal MCF at the reference BESS assumptions
Storage duration	Two-hour minimum among tested cases: £31.94/MWh-flex	Four-hour reference retained; ten durations from 1 to 72 h
Prescribed load shape	Flat £37.10; inverse £45.45 per MWh-flex	Flat case also resizes capacity; preparation alignment remains unresolved
TES thresholds	Lowest tested MCF at p50/p50: £29.76/MWh-flex	p40/p60 reference retained; 25 combinations reported
Illustrative uncertainty scenarios	TES lower MCF in 63.56% / 70.75% vs BESS-100 / BESS-200	Conditional fractions, not empirical probabilities

Result area	Finding	Interpretation
Numerical checks	Reconciliation and balance discrepancies reported in Appendix E	Internal numerical consistency; no operating-plant performance verification

The results show the estimated costs and operating consequences of the specified energy-shifting cases. TES is lower-cost at the reference assumptions, but headroom restrictions can reverse that ordering. Dispatch, input alignment and unequal accounting scopes also limit attribution of the difference to technology. Chapter 5 draws the research conclusions within these boundaries.

5. CONCLUSION

This thesis evaluated plant-integrated sensible-heat TES supplying the CCS solvent-regeneration reboiler and grid-scale lithium-ion BESS operating at the electrical interface. The analysis quantified annual flexibility and marginal cost for specified storage configurations around an NGCC+CCS reference case, using the retained model-year evidence.

The four-hour, p40/p60 TES reference gives £42.91/MWh-flex, compared with £54.41/MWh-flex for BESS-100 and £58.49/MWh-flex for BESS-200. TES therefore has the lower calculated reference cost. This conclusion applies to the stated physical, operating and accounting assumptions; the headroom diagnostic in Chapter 4 demonstrates that restricting the TES electrical credit can reverse the ordering.

5.1 Response to the research questions

The findings presented in Chapter 4 answer the research questions through four related conclusions.

RQ1: How much CCS reboiler heat can TES shift under the adopted price-based operating rules and storage constraints, and what electrical-equivalent flexibility does this represent?

Plant-integrated TES shifts the timing of heat supplied to the CCS solvent-regeneration reboiler. Charging involves foregone electrical output, while useful discharge replaces contemporaneous steam extraction and provides an electrical-equivalent flexibility credit. Under the four-hour, p40/p60 reference assumptions, TES supplies 45.63 GWh-th of useful reboiler heat over the representative model year, corresponding to 12,776.80 MWh-flex using the adopted electrical-equivalent conversion factor. This quantity is constrained by the chronological storage calculation and remains conditional on the assumed plant integration and electrical headroom.

RQ2: What annual AC electrical output and marginal cost of flexibility arise from the selected BESS configurations, and how do the results differ under a supplementary SOC-constrained, price-responsive operating case?

The retained 100 MWh and 200 MWh BESS cases, each with a 50 MW converter, supply 172,925.53 and 174,019.50 MWh of annual AC output, respectively. Their revised headline MCFs are £54.41 and £58.49/MWh-flex, using the adopted 8% real financial basis and benchmark-based non-wholesale revenue adjustment. The separate SOC-constrained price-responsive sensitivity gives £50.13 and £59.85/MWh-flex. These sensitivity results reflect different dispatch and accounting assumptions; their differences from the headline cases cannot be attributed to SOC restrictions alone.

RQ3: How do the TES and BESS marginal-cost estimates compare under their stated accounting boundaries, and how do storage duration, operating assumptions and economic parameters affect the comparison and TES installed-cost parity thresholds?

The reference TES MCF is £42.91/MWh-flex, including accepted-charging opportunity cost and useful-discharge electricity value. TES therefore has the lower headline MCF under the specified screening assumptions. With the reference BESS assumptions held fixed, parity occurs at TES installed costs of approximately £46.52/kWh-th against BESS-100 and £48.83/kWh-th against BESS-200. These thresholds indicate where the reference TES cost advantage disappears as its assumed installed cost increases; they are not forecasts of future technology costs.

Duration and dispatch-threshold sensitivities demonstrate that the reference case is not the lowest-cost tested configuration. The four-hour duration and p40/p60 rule nevertheless remain the reference assumptions. The detailed sensitivity and Monte Carlo results in Chapter 4 describe conditional scenario outcomes rather than empirical probabilities of technology superiority.

RQ4: How should differences in physical function, dispatch and model limitations shape the interpretation of the TES–BESS cost comparison?

TES supplies reboiler heat within the plant, whereas BESS stores and exports electricity at the electrical interface. A common cost per credited MWh-flex permits a screening comparison but does not establish equivalent services. The comparison also combines differences in configuration, dispatch and accounting scope. Its interpretation remains subject to the plant boundary, electrical-headroom assumptions, high-utilisation baseline and retained price–thermal alignment limitation. The headroom diagnostic demonstrates that restricting the credited TES output can reverse the headline ordering. Consequently, the results support a conditional comparison of the specified cases, rather than a universal ranking or confirmation of actual retrofit performance.

5.2 Limitations

The limitations differ in their consequences for the comparison. Table 5-1 separates a demonstrated reversal under an illustrative headroom restriction, potentially material effects whose influence remains unquantified, and restrictions on the claims supported by the study. The scenario ranges in Chapter 4 do not quantify all of these limitations.

Table 5-1: Principal limitations of the study.

Limitation and consequence	Boundary or evidence	Implication for the conclusions
Demonstrated ordering sensitivity: TES electrical headroom	All 1,075 useful-discharge hours coincide with Case 0 generation at 630.8 MW. The full external credit reaches about 646.01 MW. At 10 MW additional headroom, TES MCF is £79.31/MWh-flex.	The illustrative restriction reverses the headline ordering. It does not establish actual turbine, generator or export capacity; the reference TES credit remains conditional on sufficient headroom.

Limitation and consequence	Boundary or evidence	Implication for the conclusions
Potentially material: price–thermal alignment and reboiler-load inputs	The 8,760-hour representative sequence omits 29 February but retains clock-change settlement periods. Hourly price reconstruction does not resolve the preparation mismatch with prescribed thermal-load fractions.	Correct alignment could change TES operation and the comparison. Flat and inverse-rank load scenarios test specified alternatives but do not establish the result of a corrected aligned input series.
Potentially material: dispatch and configuration differences	TES follows the p40/p60 rule with a four-hour reference vessel. BESS retains HOMER schedules at 50 MW with 100 or 200 MWh capacity.	The cost difference combines technology, size, dispatch and accounting effects. The analysis does not quantify their separate contributions or establish a common optimum.
Potentially material: cost and revenue scope	TES includes accepted-charging opportunity cost and useful-discharge electricity value. Headline BESS uses reconstructed cash flows at 8% real and a fixed non-wholesale benchmark adjustment. Complete site-specific costs are unavailable.	Changes in cost coverage or achievable non-wholesale revenue could change the comparison. The separate BESS SOC sensitivity has a battery-only cost scope and is not a like-for-like replacement for the headline cases.
Potentially material: BESS duty and degradation	BESS-100 operates at about 5.26 EFC/day. Throughput-based replacement is included, but progressive capacity fade and simultaneous market-service commitments are not modelled.	Different duty, degradation or revenue availability could alter cost and output. The separate 20–80% SOC sensitivity uses perfect price foresight within each daily block and does not resolve actual market operation.
Potentially material: plant utilisation and market year	The retained Case 0 model-year capacity factor is 94.3%, as introduced in Section 4.1 and Table 4-1. Outages are not separately scheduled, and the analysis uses one price year.	Different utilisation, outages or market conditions could change annual storage opportunities and relative costs. The high-utilisation baseline is not a forecast of plant availability.
Scope restriction: TES heat delivery and plant representation	The adopted 630.8 MW rating is a net NGCC+CCS reference. Hourly steam-extraction and auxiliary loads are not separately simulated. Charging is not constrained hourly by HOMER excess thermal output.	The thermal and electrical credits assume the stated steam-extraction mechanism. Storage medium, heat-exchanger performance, pressure, losses beyond the adopted efficiency and retrofit integration require plant-specific evidence before actual performance can be claimed.
Scope restriction: reference choices and sensitivity coverage	The four-hour vessel and p40/p60 rule are reference assumptions. Two hours gives the lowest MCF within the tested 1–72-hour sweep; alternative thresholds also reduce calculated MCF.	The reference is not an optimal design. The £40/kWh-th TES cost is a scenario assumption, with £25–£60/kWh-th examined in sensitivity, rather than a site-specific quotation.
Scope restriction: uncertainty interpretation	Monte Carlo results use illustrative distributions for four stated inputs. Headroom, heat-delivery feasibility and corrected price–thermal alignment are not sampled.	Scenario fractions are conditional on the chosen distributions and do not represent empirical probabilities of technology superiority or encompass every material uncertainty.
Scope restriction: service capability and temporal resolution	TES supplies reboiler heat; BESS exports electricity. The calculations use hourly resolution and exclude network constraints and detailed ancillary-service performance.	A common cost per credited MWh-flex does not establish equivalent power capability, response speed or interchangeable grid services.

Limitation and consequence	Boundary or evidence	Implication for the conclusions
Scope restriction: evidence and environmental claims	Numerical reconciliation assesses consistency within the model. No operating-plant comparison, lifecycle assessment, displaced battery-capacity estimate or materials inventory is provided.	The calculations do not demonstrate actual retrofit performance, commercial readiness or reduced battery-material demand.

The headroom diagnostic provides direct evidence that the calculated ordering is sensitive to the TES electrical credit. Other unresolved effects cannot be assigned a numerical allowance from the present analysis. Plant evidence and site-specific engineering would be required before extending these screening results to actual retrofit performance.

5.3 Contribution of the study

The study makes three contributions to the screening assessment of storage associated with NGCC+CCS plants.

Chronological TES assessment: The analysis applies an hourly storage balance to reboiler-side TES and distinguishes requested charging, accepted charging, spill, useful discharge and unmet TES discharge requests. Capacity limits, thermal losses and cyclic annual closure constrain the thermal quantities used in the cost calculation. The resulting electrical-equivalent credit is then examined against an explicit headroom restriction.

Conditional cost comparison and parity thresholds: The analysis combines the TES charging opportunity cost and useful-discharge electricity value with revised BESS cash-flow accounting. At the reference assumptions, TES has lower MCF; the installed-cost parity thresholds identify where that advantage disappears as TES cost increases with the BESS assumptions held fixed. The duration, threshold and economic sensitivities show how the comparison depends on the specified cases.

Operating and accounting interpretation: The study distinguishes the retained BESS schedules from the separate SOC-constrained, price-responsive sensitivity and reports their respective cost scopes. Together with the TES headroom diagnostic, this establishes which conclusions follow from the calculations and which require additional physical or operating evidence. The comparison concerns the selected configurations and does not isolate technology from dispatch, size or accounting effects.

The implementation combines retained HOMER outputs with external Python storage calculations and sensitivity analysis. Chapters 3 and 4 and the supporting appendices document the methods, assumptions and numerical results. This workflow is an implementation of the screening analysis rather than a separate algorithmic contribution.

PlantFlex Lab provides a development-stage interface for supplementary scenario exploration. It is separate from the calculation workflow used to generate the thesis results and requires alignment with the revised methodology and findings.

5.4 Future work

Future work can extend the existing screening workflow through the following seven directions. These extensions broaden the evidence and scenarios; they do not remove the current limitations by being deferred. Plant calibration and detailed engineering remain necessary before making claims about actual performance or retrofit readiness.

Additional market years: Apply the existing Python calculations to three to five GB wholesale-price years to examine changes in charging opportunities, useful discharge, costs and parity thresholds. Retain the p40/p60 and four-hour TES reference assumptions for comparison across years. New-year scenarios should be reported separately from the retained HOMER headline schedules.

Alternative plant availability: Introduce specified lower-utilisation and outage profiles into the existing screening calculations. Examine how reduced reboiler-duty availability affects annual TES heat delivery, electrical-equivalent credit and cost. Describe these as additional operating scenarios without implying that the retained HOMER schedules have been recalculated.

Improved plant input evidence: Where suitable data become available, replace the prescribed reboiler-load inputs with plant-derived hourly evidence and check their alignment with prices and generation. Use corresponding steam-extraction and electrical-headroom information to refine the existing conversion assumptions and credit restriction. This would address input uncertainty within the present calculation structure.

Further threshold and duration comparisons: Apply the existing threshold combinations and 1–72-hour duration sweep across the additional market-year and availability scenarios. Retain the reference case and report the lowest-cost tested combinations separately. This would show whether the observed dependence on chronology and vessel size persists across conditions.

Updated cost evidence: Refresh TES installed-cost and BESS component-cost assumptions as relevant technical and commercial evidence becomes available. Apply the same documented financial methods to both pathways and recalculate the parity thresholds. Updating both technologies avoids treating future cost reductions as specific to only one pathway.

Further application of the BESS SOC sensitivity: Use the existing SOC-constrained, price-responsive calculation with additional price years and explicitly stated operating assumptions. Retain its separate cost scope when comparing outcomes, and examine how annual output, cycling and MCF vary. This extends the current operating sensitivity without treating its perfect-foresight schedule as observed market operation.

PlantFlex Lab scenario comparison: Further development could align the companion interface with the revised calculation methods and support comparisons among the documented scenarios. The application would remain a supplementary screening interface, distinct from the workflow that generated the thesis results.

5.5 Closing conclusion

The study quantifies how the selected TES and BESS configurations provide energy shifting and what that flexibility costs under the stated screening assumptions. The chronological TES calculation supplies useful reboiler heat and attributes an electrical-equivalent benefit to reduced contemporaneous steam extraction; BESS returns stored electricity at the AC interface.

The reference TES result is £42.91/MWh-flex, below the BESS headline values of £54.41 and £58.49/MWh-flex. The associated parity thresholds and sensitivity results describe the conditions governing this calculated cost advantage. Electrical headroom, dispatch differences, price–thermal alignment and accounting scope restrict its interpretation.

The contribution is a quantified, conditional comparison of the specified pathways, supported by explicit storage balances, cash-flow treatment and sensitivity analysis. Extending the existing workflow to additional market years, plant availability scenarios and improved input evidence would broaden this assessment while retaining its screening purpose.

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APPENDIX

APPENDIX A: HOMER Pro simulation output evidence

This appendix presents the retained simulation results obtained using HOMER Pro for the specified Case 0 baseline and BESS configurations. Tables A-1 and A-2 provide the numerical summaries. Two representative screenshots are retained as supplementary illustrations: the Case 0 cost summary and the BESS-100 converter-output panel. These records document the original simulation outputs; the revised financial treatment and MCF calculations are reported separately in Chapter 4. The TES pathway is calculated externally in Python rather than represented as a native HOMER thermal-storage component.

Table A-1: Retained HOMER summary results for the Case 0 baseline.

Quantity	**Unit**	**Case 0**
Net present cost	£	709,701,100
Annual operating cost	£/year	40,259,940
Generator electrical production	MWh/year	5,208,963.745
Grid sales	MWh/year	5,208,963.745
Generator operating hours	h/year	8,760
Minimum electrical output	MW	374.829
Maximum electrical output	MW	630.800
Generator capacity factor	%	94.3
Mean generator electrical efficiency	%	49.9
Generator thermal production	MWh-th/year	2,047,274.828
Boiler thermal production	MWh-th/year	45,143.508
Thermal load served	MWh-th/year	1,903,859.674
Excess thermal output	MWh-th/year	188,558.662
Boiler operating hours	h/year	1,976
Mean boiler efficiency	%	85.0

Source: retained Case 0 HOMER summary records and generator, thermal and boiler output panels.

Notes: Values reproduce the displayed HOMER summaries. Hourly post-processing uses the precision retained in the exported time series. The excess-thermal total is not an hourly constraint on TES charging and does not establish the availability of charging heat for the adopted steam-extraction mechanism.

The Case 0 cost summary records the original HOMER net present cost. The original model uses 8% nominal interest and 2% inflation; the revised cash-flow assessment in Chapter 4 uses 8% real over 25 years.

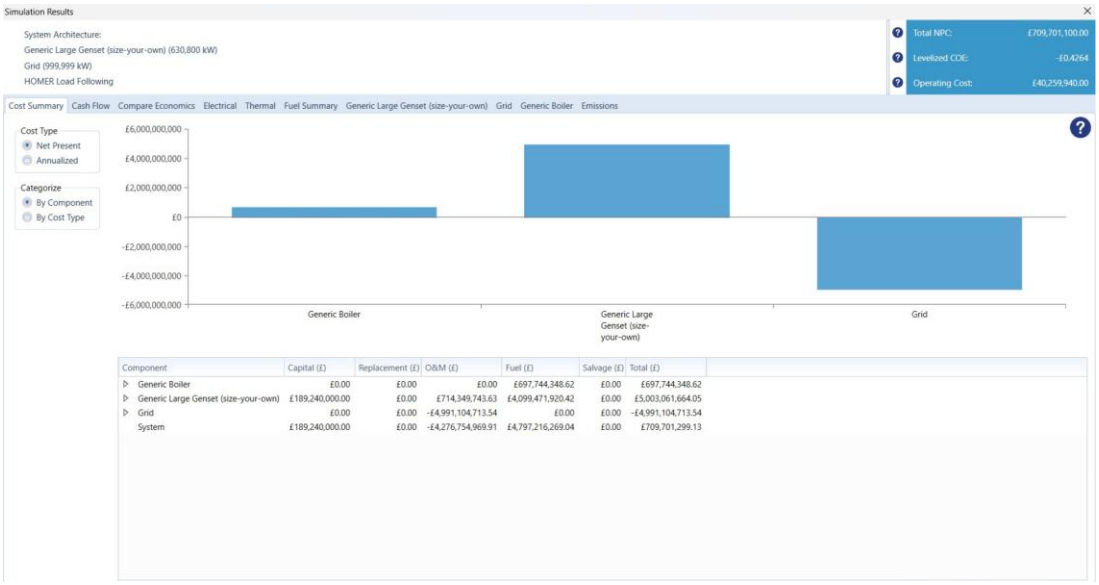


Fig. A-1: HOMER Pro cost summary for Case 0 no-storage NGCC+CCS baseline

Table A-2: Retained HOMER summary results for the BESS configurations.

Quantity	**Unit**	**BESS-100**	**BESS-200**
Net present cost	£	844,326,600	851,555,700
Incremental NPC relative to Case 0	£	134,625,500	141,854,600
Annual operating cost	£/year	48,237,150	47,520,010
Generator electrical production	MWh/year	5,208,963.745	5,208,963.745
Grid sales	MWh/year	5,168,982.429	5,163,371.470
Excess electricity	MWh/year	8.480	4,589.647
Nominal battery capacity	MWh	100	200
Usable nominal capacity reported by HOMER	MWh	85	170
Battery energy input	MWh/year	202,261.508	208,631.187
Battery energy output	MWh/year	182,035.357	187,768.068
Battery losses	MWh/year	20,226.151	20,863.119
Annual battery throughput	MWh/year	191,882.115	197,924.922
Annual equivalent full cycles reported by HOMER	cycles/year	1,919	990
Expected battery life reported by HOMER	years	3.13	6.06
Converter rating	MW	50	50
AC inverter output	MWh/year	172,925.534	174,019.500

Source: retained HOMER economic, battery and converter summaries for the two BESS configurations.

Notes: These simulation results were obtained using HOMER Pro under the original input assumptions, including an 8% nominal discount rate and 2% expected inflation. They are not the revised 8%-real incremental present costs used in the headline MCF calculation. Chapter 4 reports the revised financial treatment, external O&M and non-wholesale revenue adjustment. Battery energy output and AC inverter output represent different measurement boundaries; the latter provides the BESS MWh-flex denominator. Displayed battery-life values are rounded.

These results describe the retained HOMER cases, not the separate SOC-constrained sensitivity.

The retained BESS-100 converter panel identifies the AC output boundary used for annual MWh-flex. Battery-side energy and AC inverter output are reported separately in Table A-2.

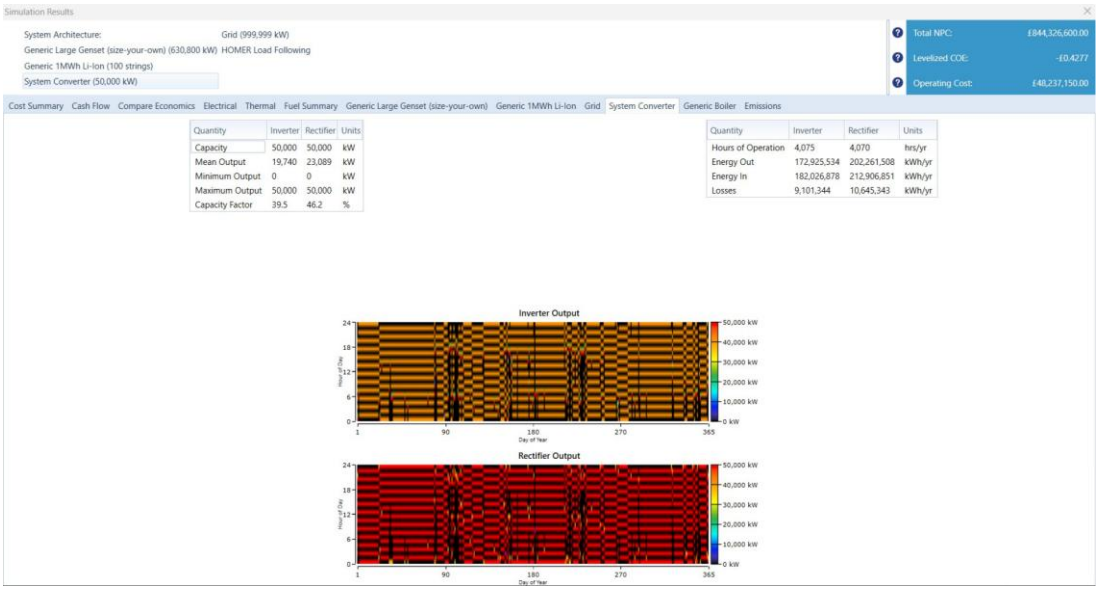


Fig. A-2: Retained HOMER converter-output summary for BESS-100 (100 MWh, 50 MW).

The TES calculation uses the thermal-load and grid-price series from the retained Case 0 hourly export. Charging, useful discharge, state of charge and the associated economic quantities are calculated externally in Python, as described in Chapter 3 and Appendix B.

HOMER serves the prescribed thermal load through recovered generator heat and a backup boiler. The external TES calculation instead assumes steam-cycle heat diversion during charging and replacement of contemporaneous reboiler steam extraction during discharge. Fired-boiler heat is not the source of the credited TES electrical benefit. The reported 188.56 GWh-th of excess thermal output is 9.90% of annual thermal demand; TES charging is not constrained against that surplus hourly.

The figure shows hourly price, BESS charging input, AC inverter export to grid and state of charge for the selected representative week. The profile illustrates the high-throughput operation of the 100 MWh case selected from the original HOMER capacity search

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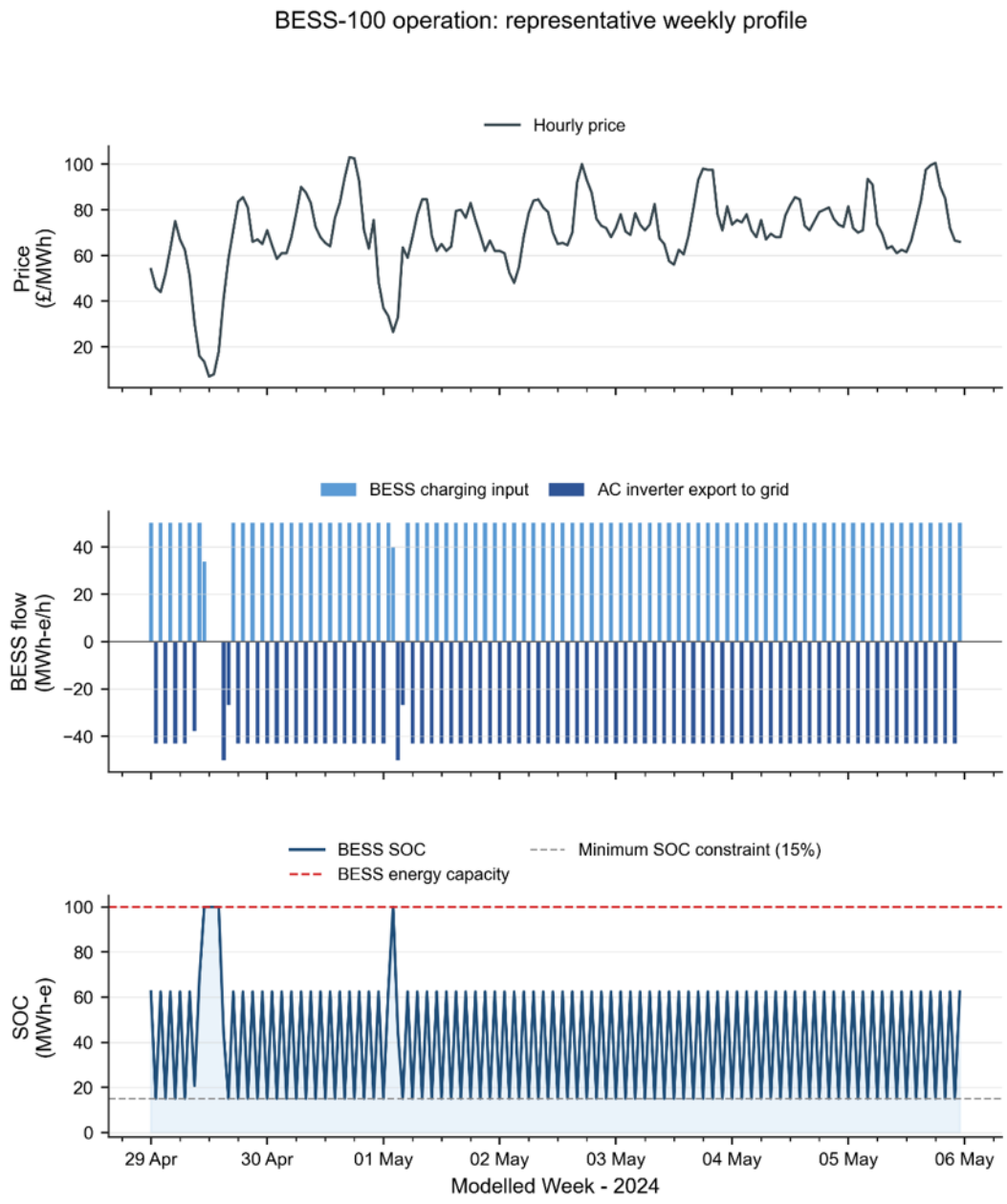


Fig. A-3: Representative weekly operating profile of the retained 100 MWh BESS case.

APPENDIX B: Python post-processing pipeline

This appendix describes the inputs, calculation stages and outputs of the Python workflow used for the results in Chapters 3 and 4. Tables B-1 to B-5 summarise the current calculation structure and its supporting materials.

B.1 Pipeline overview and rationale

Python post-processing is required because the two flexibility pathways act at different physical boundaries. The grid-scale BESS cases are represented as HOMER-native electrical-storage simulations. The plant-integrated TES pathway is represented externally as an hourly chronological state-of-charge (SOC) model applied to the Case 0 price and CCS reboiler thermal-load evidence. TES heat is discharged only to the CCS solvent-regeneration reboiler. The associated MWh-flex arises from avoided contemporaneous steam extraction rather than direct electrical generation by TES.

The TES calculation records requested and accepted charging, spill, useful reboiler discharge, unmet TES requests, hourly SOC and annual energy balances. Its MCF includes annualised capital, fixed O&M, accepted-charging opportunity cost and useful-discharge electricity value. Electrical-equivalent output remains conditional on the stated steam-extraction mechanism and electrical headroom.

The headline BESS calculation retains the HOMER operating schedules and reconstructs incremental cash flows, including fractional-year replacements, converter replacement and year-25 salvage. These cash flows are discounted at 8% real. Annualised incremental cost, external fixed O&M and the benchmark-based non-wholesale revenue adjustment are divided by annual AC inverter output. A separate SOC-constrained sensitivity uses its own dispatch and accounting scope.

The workflow reads source exports and configuration inputs, calculates the storage and economic quantities, evaluates sensitivities and produces result tables and figures. Numerical checks compare exported quantities and storage balances with the criteria reported in Appendix E.

B.2 Module architecture

Table B-1 identifies the modules used by the current pipeline. The calculation stages comprise input handling, TES operation, BESS financial assessment, sensitivity analysis and figure generation.

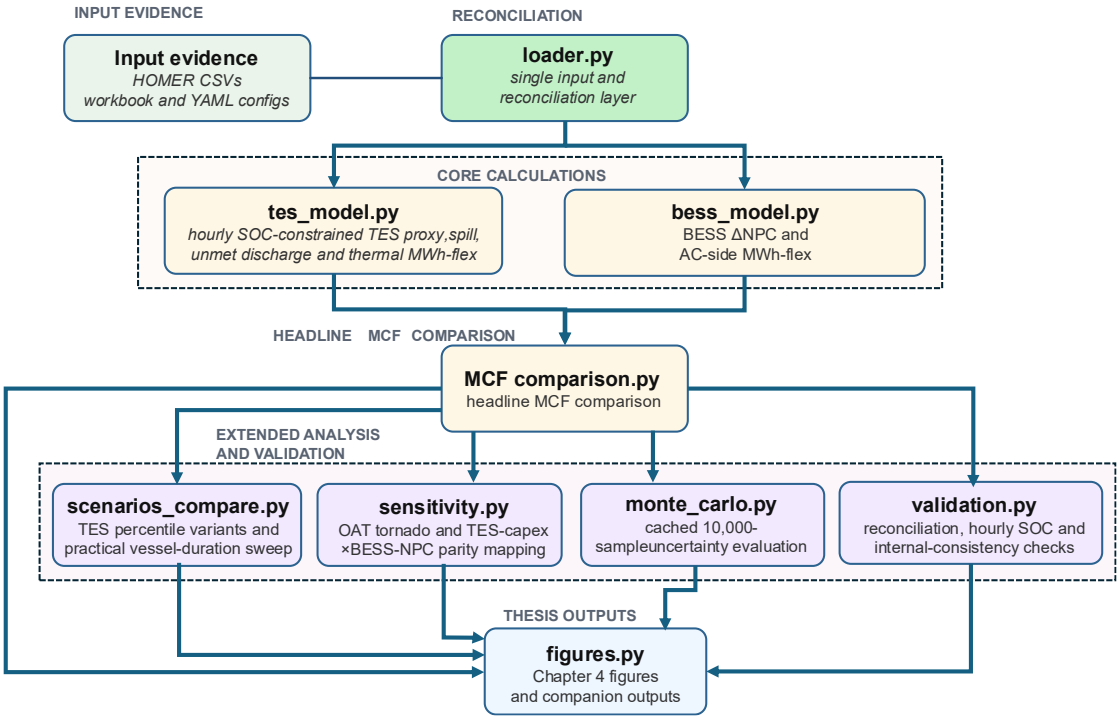


Fig. B-1: Conceptual organisation of Python post-processing. Table B-1 identifies the module names and calculation roles used in the revised pipeline.

Table B-1: Python modules and calculation roles.

Module	Calculation role	Principal output
main.py	Coordinates the reference calculations, duration sweep, BESS sensitivity and figure generation.	Current result tables and figures.
run_model.py; tes_model.py	Read Case 0 inputs; apply the chronological TES balance, threshold grid and cost assumptions.	TES hourly flows, annual summary and threshold results.
bess_mcf.py	Reconstruct and discount BESS cash flows; apply fixed O&M and the non-wholesale adjustment.	Headline BESS MCF reconciliation.
bess_practical_operation_sensitivity.py	Evaluate the separate daily SOC-constrained, price-responsive BESS cases.	Hourly and daily schedules and sensitivity summary.
r09_parity.py	Apply the current TES and BESS cost definitions to the installed-cost parity grid.	Parity thresholds and ratios.
r09_sensitivity.py	Revalue retained load-shape schedules, evaluate OAT cases and use the retained 10,000 Monte Carlo input combinations.	Load-shape, OAT and Monte Carlo results.
pipeline_data.py	Assemble current results and the central comparison for reporting.	Inputs for figures and comparison tables.

Module	Calculation role	Principal output
figures.py; TES_SOC_figure.py; BESS_SOC_figure.py	Draw the result and operating-profile figures from calculation outputs.	Figures and operating-profile summaries.

B.3 Data inputs

Inputs comprise the retained Case 0 and BESS hourly exports, HOMER summary records, the configuration file, reconstructed BESS cash flows, the Modo Energy benchmark databook and retained sensitivity schedules and sampled inputs. The 8,760 rows are used in their retained model order; the upstream price–thermal alignment limitation remains as described in Chapter 3.

Research Python code, configuration files, selected HOMER hourly exports and supporting workbooks are available through the author's GitHub repository, Marginal-Cost-of-Flexibility-in-CCS-Retrofitted-UK-Gas-Plants. The repository is not presented as a verified software release corresponding to the revised thesis. The revised calculation files and outputs are retained in the author's local research archive. Native HOMER project files are not included in the linked repository. The methods, assumptions and calculation sequence are described in Chapter 3 and Appendices B–F.

Table B-2: Principal input classes used by the Python workflow.

Input class	Quantities used	Calculation role
Case 0 hourly export	Grid price; generator output; thermal load; fuel and thermal-output quantities.	TES requests and valuation; baseline reconciliation.
BESS hourly exports	AC inverter output; rectifier input; battery input/output, SOC and energy content.	Annual electrical denominator and operating evidence.
HOMER summary records	Original NPC, operating quantities, battery capacity, life and converter rating.	Source summaries and reconciliation.
Reconstructed BESS cash flows	Initial, replacement and salvage amounts and timings; recurring incremental grid costs.	Discounted headline financial assessment.
model_config.yaml	TES parameters, financial basis, source columns, thresholds and duration grid.	Current reference and deterministic calculations.
Modo Energy 2024 databook (Jennings, 2025a)	Monthly annualised revenue components and calendar-day weights.	Non-wholesale benchmark adjustment.
Retained load-shape schedules and sampled inputs	Alternative hourly load schedules; 10,000 input combinations.	Revaluation under current cost methods and scenario distributions.

B.4 Flexibility service denominator

Annual MWh-flex provides a cost-normalisation denominator. For TES it is an electrical-equivalent credit associated with useful reboiler heat; for BESS it is AC electrical output. These quantities do not establish equivalent operational services.

Table B-3: MWh-flex denominator definitions used in the Python workflow.

Pathway	Annual MWh-flex definition	Boundary
TES	Sum of useful discharge in kWh-th × discharge conversion factor / 1,000.	Conditional electricity retained through avoided contemporaneous steam extraction.
Headline BESS	Sum of hourly inverter output in kW × 1 h / 1,000.	Electricity at the AC interface.
BESS SOC sensitivity	Sum of hourly AC export in MW × 1 h.	AC output under the separate daily SOC-constrained schedule.

The BESS denominator uses AC-side output rather than DC-side battery discharge because conversion losses are not exported to the grid. The TES denominator uses useful vessel-constrained reboiler discharge rather than requested discharge or an unconstrained annual-balance estimate.

B.5 Annualisation and economic reporting

The financial analysis uses an 8% real discount rate and a 25-year horizon. Headline BESS costs are reconstructed from the retained cash-flow evidence at their actual replacement timings, rather than applying a new capital-recovery factor to the original HOMER NPC. Recurring incremental grid costs are treated as annual cash flows. The original HOMER 8% nominal interest and 2% inflation settings are retained as source information.

Table B-4: Annualised cost treatment used in the post-processing workflow.

Reporting quantity	Annual treatment	Scope
TES net cost	Capital recovery + fixed O&M + accepted-charging opportunity cost − useful-discharge electricity value.	Numerator of the reference TES MCF.
Headline BESS before adjustment	Revised incremental present cost × CRF + £250,000 fixed O&M.	Includes reconstructed asset and incremental grid cash flows.
Headline BESS net cost	Cost before adjustment − £1,716,440.325749.	Fixed non-wholesale allowance applied to each 50 MW case.
BESS SOC sensitivity	Annualised battery initial/replacement cost + fixed O&M + AC charging cost − AC discharge value.	Separate battery-only scope; no converter capital, salvage or non-wholesale adjustment.

B.6 Calculation sequence

The calculation sequence combines the retained HOMER evidence with external TES and BESS analyses. It uses the existing simulation outputs without a new HOMER run.

1. Read and reconcile the Case 0 and BESS HOMER evidence, workbook summaries and active configuration files.
2. Run the 4 h p40/p60 TES reference calculation with chronological hourly SOC constraints and cyclic annual closure.
3. Reconstruct and discount the headline BESS cash flows; calculate MCF using the external fixed O&M, non-wholesale adjustment and annual AC output.
4. Assemble the reference comparison using TES net cost and the revised BESS headline costs.
5. Evaluate all 25 TES threshold combinations, with p40/p60 retained as reference and no action in hours tied at a shared threshold.
6. Evaluate TES durations of 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 hours; retain the four-hour reference.
7. Run the one-at-a-time sensitivity and TES capex × BESS NPC parity mapping.
8. Revalue the retained load-shape schedules and 10,000 Monte Carlo input combinations using the current TES and BESS financial definitions.
9. Evaluate the separate SOC-constrained, price-responsive BESS sensitivity and reconcile the reported quantities and storage balances.
10. Generate the Chapter 4 figures and supporting workbooks from the internally checked outputs.

A companion web interface, PlantFlex Lab, is documented in Appendix G. It is a separate screening demonstrator and is not the governing source for the thesis results.

B.7 Environment and dependencies

Table B-5: Main Python environment and dependency requirements.

Component	Role in the current workflow
Python	Execution of the calculation scripts.
pandas; NumPy	Data handling, aggregation and numerical operations.
SciPy	Daily BESS mixed-integer optimisation and numerical methods.
Matplotlib	Result and operating-profile figures.
openpyxl	Reading evidence workbooks and writing result workbooks.
PyYAML	Reading model_config.yaml.

APPENDIX C: TES reduced-order proxy algorithm specification

C.1 Rationale for the reduced-order TES proxy

The TES pathway considered in this thesis is plant-integrated sensible-hot thermal storage supplying heat only to the CCS solvent-regeneration reboiler. The stored heat is not routed through the turbine and does not generate electricity directly. Electrical-equivalent flexibility arises because useful TES discharge reduces contemporaneous steam extraction for solvent regeneration, allowing the NGCC steam cycle to retain additional electrical output during selected higher-price hours.

A chronological Python calculation applies the Case 0 price and reboiler-load series to TES. It constrains accepted charging and useful discharge by the thermal rate and stored-energy bounds, and enforces cyclic annual SOC closure. The annual benchmark used for retention removes chronology and vessel limits while retaining the dispatch-generated requests.

C.2 Algorithm specification

The TES proxy is implemented as a deterministic chronological calculation over the 8,760-hour Case 0 evidence base. The detailed mathematical formulation is provided in Section 3.3.3. Table C-1 records the implementation sequence and the principal reference-case outputs used for traceability.

Table C-1: Chronological hourly SOC-constrained TES reduced-order proxy algorithm.

Step	Chronological calculation rule	Related equations	Reference-case handling / output
Read Case 0 evidence	Read the 8,760-hour electricity-price series and the CCS solvent-regeneration reboiler thermal-load proxy.	Input evidence	8,760 hourly observations.
Apply dispatch indicators	Use non-overlapping charging and discharging indicators. At separated thresholds, charge at or below p40 and discharge at or above p60. At a shared threshold, tied-price hours receive neither request.	Equations 3-7 and 3-8	p40/p60 reference rule; shift fraction = 0.20. The reference rule is not claimed to be optimal.
Define vessel power and energy limits	Convert imported reboiler power to interval energy using $\Delta t = 1$ h. Define the TES thermal rate from the shifted peak reboiler load, and stored-energy capacity as rate × duration.	Equations 3-9 and 3-10	Peak TES rate = 54.3308 MW-th. For the 4 h reference vessel, usable capacity = 217.3232 MWh-th.
Apply split efficiencies	Represent the 90% thermal round-trip efficiency through equal charging and discharging efficiencies.	Equation 3-11	$\eta_{ch} = \eta_{dis} = \sqrt{0.90} = 0.9487$. This is an adopted modelling convention.

Step	Chronological calculation rule	Related equations	Reference-case handling / output
Calculate accepted charging and spill	Limit accepted charging by requested charging, thermal rate and available stored-energy capacity. Spill is the rejected charging request.	Equations 3-12 and 3-13	Eligible annual charge request = 138.9646 GWh-th/yr; accepted charge = 50.7016 GWh-th/yr; spill = 88.2630 GWh-th/yr.
Calculate useful discharge and unmet request	For each hour, constrain useful discharge to the reboiler by the requested discharge, peak discharging rate and stored energy available in the vessel. Record any undelivered request separately.	Equations 3-14 and 3-15	Useful discharge to the CCS reboiler = 45.6314 GWh-th/yr. Unmet discharge remains an explicit hourly diagnostic.
Update SOC chronologically	Update SOC after accepted charging and useful discharge. Enforce the usable vessel-capacity bounds in every hour.	Equations 3-16 and 3-17	SOC remains within $0 \leq SOC_t \leq E_{TES}$ throughout the modelled year.
Enforce cyclic annual closure	Require the end-of-year SOC to equal the initial SOC so that the annual result is not improved by an unaccounted inventory drawdown or surplus.	Equation 3-18	Final minus initial annual SOC = 0 kWh-th at retained precision; see Appendix E for balance discrepancies.
Aggregate annual diagnostics	Benchmark = min(0.90 × annual requested charging, annual requested discharge). Retention = useful discharge / benchmark. Calculate spill, unmet requests and stored-energy equivalent cycles separately.	Equations 3-19 to 3-23	Charge spill share ≈ 63.5%; retention versus the unconstrained annual-balance benchmark = 36.49%; equivalent full cycles = 221.33 cycles/yr.
Convert to MWh-flex	Convert useful TES discharge supplied to the reboiler into electrical-equivalent flexibility using the turbine-penalty factor.	Equation 3-20	Electrical-equivalent credit = 12,776.80 MWh-flex/year, conditional on the physical boundary.
Calculate TES net cost	Add annualised installed cost, fixed O&M and accepted-charging opportunity cost; subtract useful-discharge electricity value. Divide by credited MWh-flex.	Equations 3-4 to 3-6	Installed cost £8.693 million; annual net cost £548,299.43; MCF £42.91/MWh-flex.

Charging spill and unmet TES discharge requests describe the vessel-constrained schedule. Spill is not measured plant heat curtailment, and unmet TES requests do not imply unserved CCS reboiler demand. The retention benchmark is a calculation reference rather than evidence of charging-heat availability or electrical headroom.

C.2.1 Supporting annual TES operating-pattern visualisations

The Chapter 4 weekly and annual operating profiles are supported by two additional annual SOC visualisations. Figure C-1 groups every modelled hour by vessel-occupancy band. Figure C-2 presents the same annual SOC sequence as a day-by-hour carpet plot. Together, the figures show that the 4 h reference vessel repeatedly interacts with its upper and lower bounds under the p40/p60 rule.

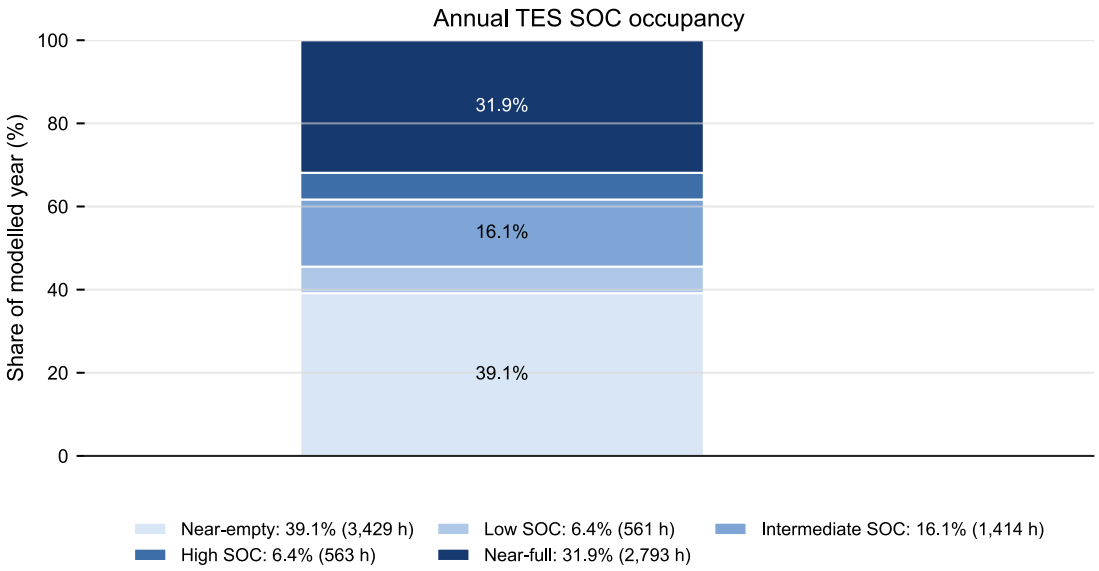


Fig. C-1: Annual TES SOC occupancy for the 4 h p40/p60 reference case. Near-empty and near-full states are defined as SOC values within 1% of the usable vessel limits.

The occupancy summary shows that the vessel is near-empty for 39.1% of the modelled year and near-full for 31.9%. The combined result confirms that the vessel frequently operates at its capacity boundaries rather than remaining predominantly within an intermediate SOC band.

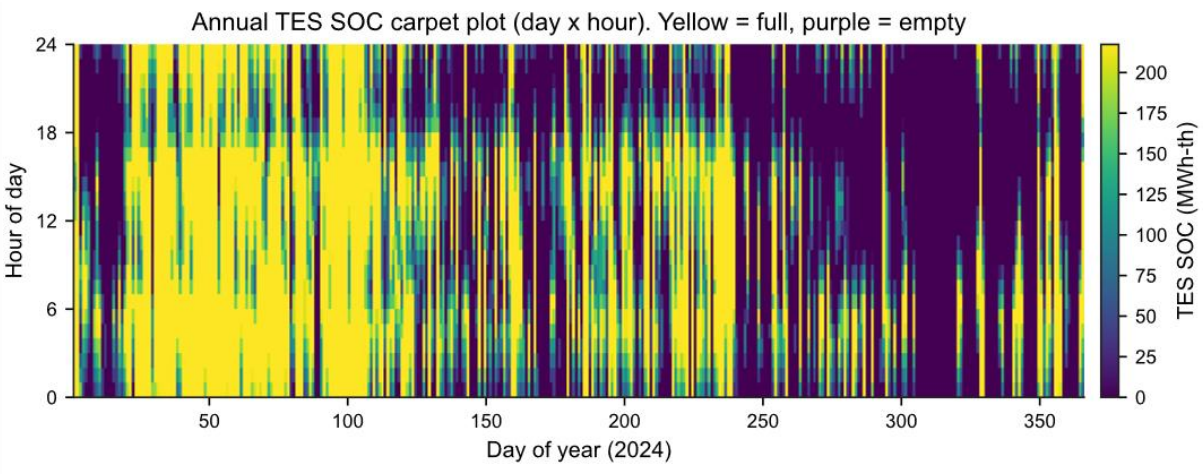


Fig. C-2 Annual TES SOC carpet plot for the 4 h p40/p60 reference case, showing hourly vessel occupancy by day of year and hour of day

The carpet plot shows clustered periods of full and empty vessel occupancy across the modelled year. This chronology explains why annual charge-discharge balancing alone is insufficient: closely grouped charging opportunities can create spill, while later high-price periods may occur after the vessel has already been depleted.

C.3 TES vessel sizing and cost basis

Stored-energy capacity is the TES thermal rating multiplied by duration: 54.3308 MW-th × 4 h = 217.3232 MWh-th in the reference case. The tested duration set is 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 hours. Four hours remains the reference; two hours gives the lowest calculated MCF within that set.

TES installed cost is assumed to be £40/kWh-th of stored-energy capacity, with £25–£60/kWh-th examined in sensitivity. The assumed package includes storage equipment, heat exchangers, pumps, piping, insulation, controls, civil works, engineering, procurement and construction, and contingency. Glatzmaier (2011), Jacob et al. (2017), Pompei et al. (2023) and IEA Energy Storage TCP (2024) provide cost context for different sensible-heat systems; they do not establish a quotation for this NGCC+CCS integration. Fixed O&M is 1% of installed cost per year.

Table C-2: TES reference sizing, cost and diagnostic basis.

Parameter	Reference value	Definition
Dispatch	p40/p60; £69/£79 per MWh	Reference price rule.
Shift fraction	0.20	Eligible share of reboiler thermal load.
Thermal rate	54.3308 MW-th	Maximum charging/discharging thermal rate.
Stored-energy capacity	217.3232 MWh-th	Four-hour reference SOC capacity.
Thermal round-trip efficiency	90%	Equal charging and discharging factors of √0.90.
Charging conversion factor	0.28 kWe/kWth	Foregone electrical output per accepted charging heat.
Discharge conversion factor	0.28 kWe/kWth	Retained electricity per useful reboiler heat.
Installed cost	£40/kWh-th; £8.692928 million	Cost per stored-energy capacity.
Fixed O&M	£86,929.28/year	1% of installed cost.
Annual benchmark	125.0681 GWh-th	Minimum of efficiency-adjusted charge requests and discharge requests.
Useful discharge / retention	45.6314 GWh-th; 36.49%	Useful heat divided by the annual benchmark.
Net annual cost / MCF	£548,299.43; £42.91/MWh-flex	Includes charging opportunity cost and discharge electricity value.

C.4 Turbine penalty factor

The electrical conversion factor represents the lost work associated with steam extraction. Charging diverts additional steam-cycle heat into TES and incurs foregone electrical output; useful discharge supplies reboiler heat and replaces contemporaneous extraction. The reference calculation applies 0.28 kWe/kWth separately to accepted charging and useful discharge (IEAGHG, 2012).

IEAGHG (2012) reports a reference steam-turbine gross output of approximately 343.5 MWe, a post-combustion MEA capture-case steam-turbine gross output of approximately 269.81

MWe and a stripper-reboiler duty of approximately 267.9 MWth. An indicative benchmark ratio is therefore:

φ_{te} = (343.5 − 269.81) MWe / 267.9 MWth = 0.275 ≈ 0.28 kWe/kWth

The rounded 0.28 kWe/kWth factor is a benchmark approximation, not a universal NGCC+CCS constant. The sensitivity analysis varies both charging and discharging factors together over 0.18–0.35 kWe/kWth. These factors convert heat flows to electrical opportunity cost and retained-output value; they are distinct from TES thermal efficiency. Actual electrical recovery also requires the plant and export headroom discussed in Chapter 4.

C.5 Scope limits of the proxy

The TES proxy is designed for screening-level techno-economic comparison. The chronological hourly calculation captures vessel saturation, accepted charging, charging spill, useful discharge, unmet discharge, storage losses and cyclic annual SOC closure. It does not resolve sub-hourly reboiler inertia, solvent kinetics, heat-exchanger transients, detailed tank stratification, pressure-level matching, storage-medium selection, auxiliary-equipment design, retrofit constructability or part-load variation in the turbine-penalty factor.

The proxy is not a dynamic steam-cycle model and is not an empirical validation of TES performance at an operating NGCC+CCS plant. Its purpose is to provide a transparent reduced-order representation of reboiler-side thermal shifting for the marginal-cost comparison. TES and BESS remain distinct assets operating at different physical boundaries: TES modifies the CCS reboiler-side thermal coupling, while BESS provides external grid-side electrical flexibility.

APPENDIX D: Adopted numerical inputs and configuration

This appendix consolidates the current reference assumptions, their evidence boundaries and the sensitivity settings. Original HOMER outputs are distinguished from reconstructed settings and from assumptions used in the revised financial and storage calculations.

D.1 Financial, generator and CCS parameters

Table D-1 records the financial basis and generator/CCS reference information. The 49.9% mean generator electrical efficiency and 85.0% mean boiler efficiency are HOMER outcomes reported in Appendix A, rather than independently verified input settings. Original HOMER projects specify 8% nominal interest and 2% inflation; the revised assessment uses 8% real over 25 years.

Table D-1: Financial, generator and CCS reference assumptions.

Parameter	Value	Basis and qualification
Real discount rate	8%	Revised analysis; constant-price financial basis.
Project horizon	25 years	Annualisation period.
Capital recovery factor	0.093678779/year	8% real over 25 years.
Generator and CCS reference assumptions		
Net NGCC+CCS reference electrical output	630.8 MW	Alruwaili et al. (2025), Table 6: 485.4 MW gas-turbine output plus 202.8 MW steam-turbine output, less 57.4 MW auxiliaries. This CCS-adjusted reference point does not establish additional turbine-generator or grid-export headroom.
CO_2 capture fraction	90%	Alruwaili et al. (2025), Applied Thermal Engineering, 281, 128619, DOI: 10.1016/j.applthermaleng.2025.128619. This denotes the CO_2 capture fraction, not a 90% reduction in overall emissions intensity.
Reconstructed generator fuel relationship	$F \approx 10{,}967.77 + 0.18448245P$	F is fuel consumption in m³/h and P is electrical output in kW. Recovered from Case 0 hourly fuel and electrical-output records; external fuel-curve calibration is not established.
Reconstructed gas-price equivalent	Approximately £0.30/m³	Recovered from Case 0 fuel-consumption, fuel-cost and generation-cost records. The original price year is not established.
Recorded generator capital entry	£189.24 million, equivalent to £300/kW	The equipment and installation scope is not established; this is not presented as a complete NGCC+CCS project-cost estimate.
Reference thermal-load multiplier	1.10	Study-defined elevated-heat-demand scenario, not a measured efficiency or standard CCS penalty.

D.2 TES parameters

Table D-2 distinguishes storage efficiency, electrical conversion and the stored-energy cost basis. Useful heat is supplied to the CCS reboiler, and its electrical-equivalent credit remains conditional on the physical boundary.

Table D-2: TES input parameters and derived reference-case quantities.

Parameter	Value	Definition or qualification
TES boundary	Steam-cycle diversion on charge; reboiler heat on discharge	Electrical costs and benefits use the stated steam-extraction mechanism.
Reference dispatch	p40/p60	£69/£79 per MWh in the retained price series.
Shift fraction	0.20	Share of eligible reboiler load.
Thermal round-trip efficiency	90%	Adopted constant efficiency.
Charging / discharging thermal efficiencies	√0.90 each	Equal split; distinct from electrical conversion factors.
Charging opportunity-cost conversion	0.28 kWe/kWth	Applied to accepted charging heat.
Discharge electricity-retention conversion	0.28 kWe/kWth	Applied to useful reboiler heat.
Reference duration	4 h	Reference assumption.
Duration sensitivity	1, 2, 3, 4, 6, 8, 12, 24, 48, 72 h	Two hours has the lowest MCF among tested durations.
Thermal rating	54.3308 MW-th	Derived from shifted peak thermal load.
Stored-energy capacity	217.3232 MWh-th	Thermal rating × reference duration.
Installed cost	£40/kWh-th; range £25–£60/kWh-th	Assumed installed package per stored-energy capacity.
Fixed O&M	1% of installed cost/year	Fixed annual allowance.
SOC constraints	Hourly capacity bounds; cyclic annual closure	End-of-year SOC equals initial SOC.
Terms not separately modelled	Auxiliary electricity; time-dependent standing loss; variable O&M	Omission does not imply physically zero consumption, loss or cost.

D.3 BESS parameters

Table D-3 separates the retained HOMER cases and revised headline financial treatment from the SOC-constrained sensitivity. The cost entries do not establish complete installed-project costs. The non-wholesale adjustment uses the calendar-day-weighted 2024 monthly rates in Jennings (2025a), How GB batteries earned revenues in 2024: a guide to operational strategies, accompanying Modo Energy databook, sheet “1. index”. Wholesale revenue is excluded. Applying the remaining benchmark to the full 50 MW rating is a screening assumption; actual service availability is not co-optimised.

Table D-3: BESS assumptions and calculation boundaries.

Parameter	Value or treatment
Panel A: headline BESS	Retained HOMER operation; revised financial treatment
Nominal battery capacities	100 and 200 MWh
Converter rating	50 MW for both cases
Minimum SOC	15%
Battery round-trip efficiency	90%
Rectifier efficiency	95%
Inverter efficiency	95%
Combined conversion efficiency	0.90 × 0.95 × 0.95 = 81.225%
Lifetime throughput	6,000 equivalent full cycles
Battery initial and replacement cost	£165/kWh of nominal capacity; adopted 2025 cost-scenario basis
Converter capital cost	£300/kW; £15 million for 50 MW
Initial battery-plus-converter cost	£31.5 million for BESS-100; £48 million for BESS-200
External fixed O&M	£250,000/year per case
Non-wholesale revenue adjustment	£34,328.806515/MW-year, applied to 50 MW: £1,716,440.325749/year per case
Financial treatment	Retained schedules and reconstructed replacement/salvage cash flows, re-discounted at 8% real over 25 years
Panel B: separate SOC sensitivity	Different dispatch and battery-only cost scope
Nominal capacity / converter rating	100 or 200 MWh / 50 MW
SOC operating range	20–80%
Daily initial and terminal SOC	50%
Dispatch	Daily price-responsive optimisation with perfect 24-hour foresight; simultaneous charging and discharging prohibited
AC-to-AC round-trip efficiency	81.22%, split equally between charging and discharging
EFC ceiling	None
Battery initial and replacement cost	£165/kWh; battery-only asset scope
Fixed O&M	£250,000/year
Replacement rule	Earlier of 6,000 realised EFC or 10 years; replacements occur in years 10 and 20 in both calculated cases
Financial basis	8% real; 25 years
Salvage and non-wholesale revenue	Neither included
Capacity fade	Not modelled

D.4 Sensitivity and Monte Carlo settings

Table D-4 records the deterministic cases and illustrative Monte Carlo input distributions. The current analysis reuses the retained 10,000 sampled input combinations. BESS replacement and salvage cash flows are re-discounted at each tested or sampled rate, while the non-wholesale adjustment remains fixed.

Table D-4: Deterministic sensitivity and Monte Carlo settings.

Analysis input	Reference	Tested values or distribution
TES thresholds	p40/p60	Charging p10, p20, p30, p40, p50 × discharging p50, p60, p70, p80, p90; 25 cases. No action at tied shared-threshold prices.
Reboiler load shape	Retained prescribed profile	Flat same-mean and inverse-rank same-distribution schedules.
TES duration	4 h	1, 2, 3, 4, 6, 8, 12, 24, 48, 72 h.
TES installed cost	£40/kWh-th	OAT £25–£60; Monte Carlo triangular (25, 40, 60).
Both electrical conversion factors	0.28 kWe/kWth	OAT 0.18–0.35; Monte Carlo triangular (0.18, 0.28, 0.35).
TES shift fraction	0.20	OAT 0.10–0.30; not sampled in Monte Carlo.
BESS incremental-NPC multiplier	1.00	OAT 0.85–1.15; Monte Carlo triangular (0.85, 1.00, 1.15).
BESS multiplier: parity map	1.00	0.60–1.40; applies to aggregate incremental present cost, not battery capex alone.
Real discount rate	8%	OAT 6–10%; Monte Carlo uniform 6–10%, common to both pathways.
Non-wholesale adjustment	£34,328.806515/ MW-year	Fixed at £1,716,440.325749/year per 50 MW case; not sampled.
Monte Carlo scenarios	10,000	Retained input combinations; four illustrative independent sampled parameters.
Original sampling seed	20260425	Records the retained sample set; not a claim of complete-study reproducibility.

The parity grid uses TES costs of £25, £30, £35, £40, £45, £50, £55 and £60/kWh-th and BESS multipliers from 0.60 to 1.40. The multiplier scales aggregate incremental present cost, including incremental grid cash flows, while external O&M and the non-wholesale adjustment remain fixed. Monte Carlo fractions describe outcomes under the specified input distributions; headroom, heat-delivery feasibility and corrected price–thermal alignment are not sampled.

APPENDIX E: Internal consistency evidence

E.1 Checking structure

The checks compare retained HOMER summaries with hourly-export totals and examine energy balances and SOC constraints in the revised storage calculations. They assess numerical consistency within the stated equations and inputs. Literature supports particular assumptions but is not treated as a numerical validation score; operating-plant validation is not established.

E.2 Numerical reconciliation and energy-balance checks

The table distinguishes differences between retained HOMER summaries and hourly-export totals from energy-balance discrepancies in the revised storage calculations. Tolerances are numerical checking criteria used in the workflow, rather than measures of plant-model accuracy.

Table E-1: Numerical reconciliation and storage energy-balance discrepancies.

Check	Absolute discrepancy	Checking tolerance
Retained Case 0 and both BESS cases: annual generator output, hourly-export sum versus HOMER summary	32.5 kWh in each case	1,000 kWh
Retained Case 0: annual boiler thermal output, hourly-export sum versus HOMER summary	3.52 kWh-th	1,000 kWh-th
Retained BESS-100: annual excess electricity, hourly-export sum versus HOMER summary	0.468 kWh	1,000 kWh
Retained BESS-200: annual excess electricity, hourly-export sum versus HOMER summary	0.2878 kWh	1,000 kWh
Revised TES reference: maximum absolute hourly stored-energy balance discrepancy	7.28×10^{-12} kWh-th	10^{-6} kWh-th
Revised TES reference: absolute annual stored-energy balance discrepancy	4.48×10^{-9} kWh-th	10^{-6} kWh-th
Revised TES reference: final minus initial annual SOC	0 kWh-th	10^{-6} kWh-th
BESS-100 SOC-constrained sensitivity: absolute annual stored-energy balance discrepancy	0 MWh	10^{-6} MWh
BESS-200 SOC-constrained sensitivity: absolute annual stored-energy balance discrepancy	1.46×10^{-11} MWh	10^{-6} MWh
Both BESS SOC-constrained sensitivity cases: maximum absolute daily terminal-SOC discrepancy	0 MWh in each case	10^{-6} MWh

The TES hourly balance compares initial stored energy plus the charging increment with storage withdrawal plus final stored energy. Its annual balance applies the same accounting over the model year. The BESS annual balance compares efficiency-adjusted AC charging energy with the stored-energy withdrawal corresponding to AC export. Reported zero discrepancies denote zero at the retained computational precision. These results concern

internal numerical consistency and do not establish the physical accuracy of the plant representation.

E.3 Reference calculation summary

Table E-2 summarises the current reference results and selected sensitivity outcomes. TES MCF includes charging opportunity cost and useful-discharge electricity value. The headline BESS costs use the revised financial treatment and fixed non-wholesale adjustment; the SOC sensitivity retains its separate scope.

Table E-2: Reference calculation summary.

Metric	Reported value	Interpretation
TES reference	p40/p60; 4 h; £40/kWh-th	Reference assumptions.
Accepted charge	50.7016 GWh-th/year	Heat accepted at the charging boundary.
Charging spill	88.2630 GWh-th/year; 63.51%	Rejected share of requested charging.
Useful reboiler discharge	45.6314 GWh-th/year	Useful heat after storage losses.
Unmet TES request	125.6763 GWh-th/year	Requested TES contribution less useful discharge; not unserved CCS demand.
Annual benchmark / retention	125.0681 GWh-th; 36.49%	Retains dispatch requests but removes chronology and vessel constraints.
Equivalent full cycles	221.33/year	Stored-energy cycling measure.
TES electrical-equivalent credit	12,776.80 MWh-flex/year	Conditional on steam-extraction recovery and headroom.
TES MCF	£42.91/MWh-flex	Annual net cost divided by electrical-equivalent credit.
Headline BESS-100 / BESS-200 MCF	£54.41 / £58.49 per MWh-flex	Revised 8% real financial treatment.
BESS SOC sensitivity: 100 / 200 MWh	£50.13 / £59.85 per MWh-flex	Separate operating and accounting scope.
TES parity cost: BESS-100 / BESS-200	£46.52 / £48.83 per kWh-th	Reference BESS assumptions held fixed.
TES lower than BESS-100 / BESS-200	63.56% / 70.75% of scenarios	Conditional Monte Carlo fractions.
TES at 10 MW additional headroom	£79.31/MWh-flex	Illustrative restriction reverses headline ordering.
Lowest-cost tested TES duration	2 h; £31.94/MWh-flex	Four-hour reference retained.

APPENDIX F: Model algorithm listings

This appendix summarises the principal algorithm logic used in the calculations. The pseudocode should be read alongside the equations in Section 3.3 and the assumptions in Appendix D. Appendix B states the availability and version limitations of the associated research materials.

F.1 TES proxy algorithm

The TES pathway is calculated chronologically over the 8,760-hour Case 0 evidence base. Stored heat is discharged only to the CCS solvent-regeneration reboiler. Electrical-equivalent flexibility arises from avoided contemporaneous steam extraction rather than direct electricity generation by TES.

```
Inputs: retained hourly price p[t] in £/kWh; reboiler power in kW;
  Δt = 1 h; shift fraction α; duration h; thermal efficiency ηTES.
Convert power to interval energy: Qreb[t] = reboiler_power[t] × Δt.
Set ηch = ηdis = sqrt(ηTES).
Set Pmax = α × max(reboiler_power); Emax = Pmax × h.
Calculate charging and discharging price thresholds.
If thresholds are separated:
  request charge where p[t] ≤ pch; discharge where p[t] ≥ pdis.
If thresholds coincide:
  request charge below the shared threshold and discharge above it;
  request neither action during tied-price hours.
Determine initial SOC such that final SOC equals initial SOC.
For each hour:
  Qch,req = α × Qreb[t] when charging is eligible; otherwise zero.
  Qdis,req = α × Qreb[t] when discharging is eligible; otherwise zero.
  Qch,acc = min(Qch,req, Pmax × Δt, (Emax − SOCprevious)/ηch).
  Qdis,use = min(Qdis,req, Pmax × Δt, ηdis × SOCprevious).
  spill = Qch,req − Qch,acc; unmet = Qdis,req − Qdis,use.
  SOCnew = SOCprevious + ηch × Qch,acc − Qdis,use/ηdis.
Check SOC bounds, non-negative flows and cyclic annual closure.
```

```
Aggregate requested and accepted charging, spill, useful discharge,
  unmet requests and thermal loss over the model year.
Benchmark = min(ηTES × sum(Qch,req), sum(Qdis,req)).
Retention = sum(Qdis,use) / Benchmark.
EFC = sum(Qdis,use) / (ηdis × Emax).
MWh-flex = φdis × sum(Qdis,use) / 1,000.
Installed cost = unit installed cost × Emax.
Charging opportunity cost = sum(p[t] × φch × Qch,acc[t]).
Discharge electricity value = sum(p[t] × φdis × Qdis,use[t]).
Net annual cost = installed cost × CRF + fixed O&M
  + charging opportunity cost − discharge electricity value.
TES MCF = net annual cost / MWh-flex, where output is positive.
Use separate φch and φdis factors, each 0.28 in the reference case.
```

The reference case uses p40/p60 thresholds, a 4 h vessel, a 20% shift fraction, 90% thermal round-trip efficiency and a TES unit-capex assumption of £40/kWh-th. The threshold rule and vessel duration are reference assumptions rather than optimised design variables.

F.2 BESS post-processing algorithm

Headline BESS calculations use the retained HOMER schedules and reconstructed cash flows. The supplementary sensitivity calculates new daily operating schedules under a separately stated SOC and cost boundary.

```
Headline BESS: for each retained 100 or 200 MWh / 50 MW case:
  retain hourly AC inverter output and operating evidence;
  reconstruct initial, fractional-year replacement and salvage cash flows;
```

```
  discount each asset cash flow at 8% real over 25 years;
  include recurring incremental grid costs on an annual basis;
  annualise the combined incremental present cost and add fixed O&M;
  subtract the calendar-day-weighted non-wholesale benchmark × 50 MW;
  divide annual net cost by annual AC inverter output in MWh.
  Report MCF before and after the non-wholesale adjustment.

Separate SOC sensitivity: for each 100 or 200 MWh / 50 MW case:
  divide the 8,760 prices into 365 consecutive 24-hour model blocks;
  impose 20–80% SOC and 50% initial and terminal SOC each day;
  use equal charging/discharging factors of sqrt(0.8122);
  optimise daily electricity value with perfect 24-hour price foresight;
  prohibit simultaneous charging and discharging; impose no EFC ceiling;
  aggregate AC charging, AC export, SOC and realised EFC;
  use the earlier of 6,000 EFC or 10 years for battery replacement;
  discount battery initial and replacement costs at 8% real over 25 years;
  include fixed O&M and charging cost less discharge value;
  exclude converter capital, salvage and non-wholesale adjustment;
  divide annual net cost by annual AC export.
  Report this sensitivity separately from the headline cases.
```

F.3 Deterministic sensitivity, parity and Monte Carlo algorithm

The sensitivity calculations distinguish chronological schedule changes from financial revaluation of retained schedules. The current Monte Carlo analysis uses retained input combinations under the four illustrative distributions specified in Appendix D.

```
Thresholds:
  evaluate charging p10–p50 × discharging p50–p90 at 10-point intervals;
  run the chronological TES balance for all 25 combinations;
  retain p40/p60 as reference and exclude action at tied shared prices.
Duration:
  evaluate 1, 2, 3, 4, 6, 8, 12, 24, 48 and 72 hours;
  recalculate stored-energy capacity, flows and net cost for each case.
Load shape:
  revalue retained reference, flat and inverse-rank thermal schedules;
  use each schedule's capacity, useful heat and charging/discharge prices.
One-at-a-time analysis:
  vary one specified input while retaining the other reference inputs;
  vary both TES electrical conversion factors together;
  re-discount BESS replacement/salvage cash flows at each tested rate.
Parity:
  vary TES cost over £25–£60/kWh-th and BESS multiplier over 0.60–1.40;
  scale aggregate BESS incremental present cost by the multiplier;
  keep external O&M and the non-wholesale adjustment fixed;
  calculate TES/BESS MCF ratios and installed-cost parity thresholds.
Monte Carlo:
  read the retained 10,000 combinations of TES cost, electrical factor,
    BESS incremental-NPC multiplier and common real discount rate;
  use reference physical schedules and the current net-cost definitions;
  re-discount BESS asset cash flows at each sampled rate;
  retain the fixed non-wholesale adjustment;
  report MCF distributions, ratios and fractions with lower TES MCF.
Interpret scenario fractions as conditional on the illustrative inputs.
```

The BESS multiplier scales aggregate incremental present cost, including embedded grid cash flows. It is not a battery-capital multiplier or a new dispatch optimisation. Physical headroom and price–thermal alignment uncertainties remain outside the sampled distributions.

F.4 Internal-check algorithm

Numerical checks compare retained quantities and storage balances with stated criteria. They assess consistency within the calculation and do not establish operating-plant accuracy.

```
Reconcile retained HOMER summary quantities with hourly-export totals.
For TES:
  compare initial energy plus accepted charging with withdrawal plus final energy;
  check hourly SOC bounds, annual closure and non-negative spill/unmet requests;
  distinguish requested heat, accepted heat and useful discharge.
For the BESS SOC sensitivity:
  compare efficiency-adjusted AC charging with stored-energy withdrawal;
```

```
  check daily terminal SOC, capacity limits and exclusive charge/discharge.
Report numerical discrepancies and applicable tolerances in Appendix E.
Review source support for assumptions separately from numerical checks.
```

Appendix E reports the numerical reconciliation and energy-balance discrepancies. These quantities concern the calculation’s internal consistency, rather than measured performance of an integrated plant.

APPENDIX G: Plantflex-lab interactive research demonstrator

G.1 Purpose and status

PlantFlex Lab is a development-stage companion demonstrator for exploring NGCC+CCS flexibility scenarios. It requires updating to reflect the revised thesis methodology and findings. The numerical results reported in this thesis were generated through the separate HOMER–Python calculation workflow.

G.2 Prototype screening functions

Table G-1: Prototype functions of PlantFlex Lab.

Prototype function	Intended role
Scenario interface	Explore user-selected storage, CCS, market and economic assumptions.
Preliminary TES sizing	Present indicative storage power and energy quantities.
External-data interface	Support exploration with user-provided time-series inputs.
Sensitivity interface	Compare specified scenario assumptions and indicative outcomes.
Scenario summary	Present inputs and outputs for comparison.

G.3 Access and development status

The web interface is available at the address below. The application source code is not supplied as part of this thesis. Availability of the separate research calculation materials is described in Appendix B. Further development of PlantFlex Lab is identified as future work.

Website: https://plantflexlab.xyz/

Table G-1 describes prototype functions. The application requires alignment with the revised thesis and is not the source of the reported calculation results.