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Optimal Operation of a Public Health Facility considering Energy Storage Retrofits#

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ABSTRACT

Integrated energy systems can benefit substantially from flexibility provision in their operations. This paper explores the operational cost optimisation of a UK public facility dedicated to health services by harnessing the flexibility gained from available gas and electricity grid inputs, a combined heat and power unit, and integration of thermal and electrical energy storage units into the local network. The optimisation algorithm assists in the sizing of the storage units under different cases of fuel price and energy storage efficiency. Optimal integration of energy storage results in operational cost savings of £7.6/day under normal operating conditions and of £64.7/day for an elevated gas price. The findings are based on real-time energy price and demand profiles and reveal that the local energy system benefits more from the thermal stores than from electrical energy storage.

Keywords: energy hub, energy storage, integrated energy system, optimal scheduling, optimal cost, demand-side management.

NONMENCLATURE

Abbreviations and Symbols	
C	Daily operational cost
C_m	Modified daily operational cost
$C^{E}_{grid,i}$, $C^{G}_{grid,i}$	Cost of consuming electricity and gas, respectively, at period *i*, (£/kWh)
$P^{E}_{grid,i}$, $P^{G}_{grid,i}$	Power input to the hub from the electricity and gas network, respectively (kW)
$P^{E}_{d,i}$, $P^{H}_{d,i}$	Power demand of electricity and heat at period *i*, respectively.
$P^{TES}_{ch,i}$, $P^{TES}_{dis,i}$	Charging and discharging power of the TES at period *i*, respectively (kW).
$P^{B}_{ch,i}$, $P^{B}_{dis,i}$	Charging and discharging power of the battery at period *i*, respectively (kW).
$\eta^{g/e}_{CHP}$	Conversion efficiency of the CHP from gas to electricity
$\eta^{g/h}_{CHP}$	Conversion efficiency of the CHP from gas to heating
P	Penalty parameter

1. INTRODUCTION

Modern energy systems are required to handle multiple energy forms and trade-offs simultaneously. A mixed interaction of energy vectors is conducive to cogeneration and efficient energy utilisation, besides increasing energy availability. This has fostered substantial development and deployment of integrated energy systems (IESs) around the world which incorporate coupling technologies between the energy vectors [1]-[5]. Fluctuations in energy demand and prices trigger such systems to adjust their behaviour. This invites the use of ancillary technologies to maximise the system's reliability and reduce operational costs.

Energy storage devices are effective ancillary utilities for energy systems [6]. Events causing abrupt disruptions in the supply of energy vectors such as gas or electricity could potentially render these devices into immediate necessities [7, 8]. In addition to supporting unforeseen circumstances, energy stores may facilitate demand-side management in the day-to-day operation of an energy system [9].

Both thermal energy storage (TES) and electrical energy storage (EES) devices are sought widely to introduce flexibility into energy systems [10, 11]. Using energy stores, the systems can import additional energy during off-peak hours which could be stored for later use during the peak hours of energy price and demand. This flexible operation offers the opportunity to optimise the operation of the overall system. For example, the rate and time at which a storage component should be charged or discharged at different hours during the operation cycle need to be decided optimally to derive the maximum cost benefits. Also, the size of the storage units needs to be optimally designed to warrant flexible system operation.

A framework enabling the steady-state modelling of IESs, termed energy hub, was introduced in [2]. A method for the optimal operation of the energy hub, based on optimal power flows, was provided in [4]. Research work building on these seminal references has been conducted to assess the optimal operation of IESs considering the diversity of their components and their environmental and economic impacts.

Different optimisation algorithms have been proposed in the literature for the analysis of IESs. A hierarchical decoupling algorithm to ensure the optimal dispatch of an IES was presented in [12], where a real heat network is implemented and the impact of the coupling degree of the system is considered. In [13], a new arrangement for a combined heat and power (CHP) system is proposed, with the effects of parameters such as air to fuel ratio, compression ratio, and pressure ratio being considered in the optimisation algorithm. The genetic algorithm presented in this reference also enables the reduction of carbon emissions. The studies in [12] and [13] evidence the applicability of different optimisation algorithms to model the operation of IESs.

Most studies incorporating energy stores into the operation of IESs address the sizing and scheduling of the storage units in isolation [11]. For instance, the effects of the TES size on the performance of an IES were studied in [14]. In [15], the optimisation of an IES including a CHP unit and a TES tank was conducted using mixed integer linear programming. This work is relevant as it shows that the TES tank enables a 14% profit in the operation of the IES. An energy cost minimisation strategy involving a CHP unit, the flexible load management of a heating, ventilation and air-conditioning (HVAC) system, and of the charging/discharging control of EES and TES systems was proposed in [16]. This is also a relevant reference as it considers the concurrent operation of two different types of energy stores within the IES.

Despite the breadth of relevant research work in the area, thorough studies utilising real-time sourced data to concurrently assess the selection, scheduling and sizing of different types of energy stores have been limited. This paper builds upon this less explored alternative and presents a methodology to capitalise on the flexibility provision of TES and EES units to an IES. To this end, an optimisation algorithm which minimises the daily operational cost while meeting the local electricity and heat demand with time-varying energy prices is presented. In parallel to this, the algorithm determines the minimum size and the type of energy storage unit required to attain the minimum daily operational cost.

To gain a pragmatic insight into the performance of the optimisation algorithm, real-time energy system's data from a public health care facility in the UK was adopted. This helps to demonstrate the applicability of the work presented in this paper to a real practical system and to illustrate how its operation could benefit from the integration of energy storage systems.

2. SYSTEM UNDER STUDY

2.1 System description

The system under investigation is the IES at Queen Elizabeth Hospital (QEH) King's Lynn—a public health facility in the Norfolk County in England, UK. It considers a two-storey building within an approximate area of 25,000 m^2, and it is connected to an electricity network and a gas supply network. Two CHP units (one in stand-by) and four gas boilers (two in stand-by) are used to satisfy the electricity and heating demands [6].

Fig. 1 shows a high-level schematic of the system. In line with the push to decarbonise the public health services in the UK [17], it is assumed that the gas boilers are not in service for this study. Only the CHP unit normally operating is considered. This can produce heat and electricity in parallel when gas is fed into it. Electricity can also be obtained from the available grid facility to meet the hospital's electricity demand.

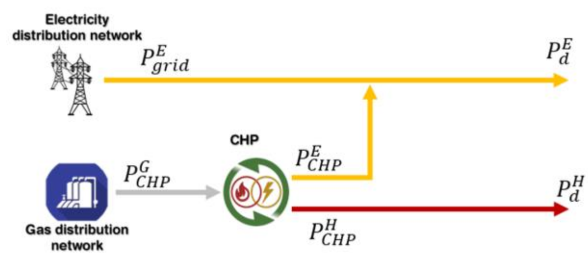

Fig. 1. Schematic of the IES under study (base case).

To enhance the cost-effectiveness of the system, TES and EES units are retrofitted into the system, as shown in Fig. 2. The upgraded IES can be leveraged to the maximum extent by optimally scheduling the system's utilities and adequately sizing the storage units.

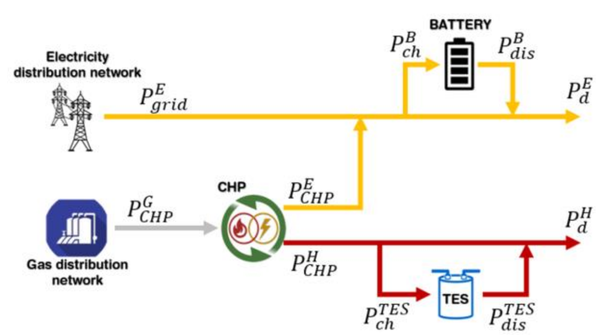

Fig. 2 Schematic of the upgraded-IES with TES and EES units.

2.2 System modelling

The optimised IES is expected to select the appropriate mix of intake gas and electricity at every hour, so that the overall daily operational cost is minimised while the energy demand is met.

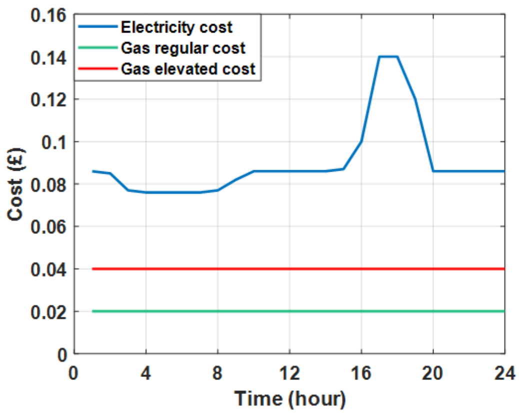

Fig. 3. Hourly gas and electricity cost.

Fig. 3 shows the daily price profiles for gas and electricity adopted in this paper. These were defined considering average market prices. Additionally, in order to assess the effect of sudden gas price surge owing to unanticipated changes in gas trade policies (e.g. due to geopolitical conflicts affecting energy security [18, 19]), another gas pricing profile was assessed, which doubles the price considered under normal operation (Fig. 3). Fig. 4 shows the heat and electricity demand profiles. To meet the energy demand, there are provisions for drawing electricity and gas from their respective grids.

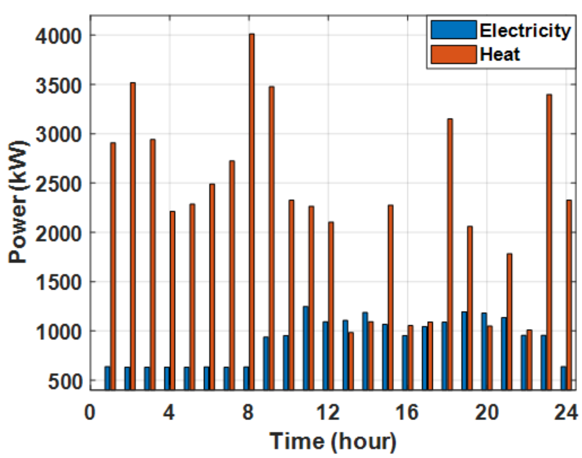

Fig. 4. Hourly electricity and heat demand.

The system was modelled using the energy hub approach, where input energy vectors can be either stored or converted to another form of energy using a coupling technology, and then released as output energy vectors [2].

The total daily operational cost is calculated from the amount of gas and electricity consumed every hour. This is mathematically expressed as:

$$C = \sum_{i=1}^{24} [(C_{grid,i}^{E} \times P_{grid,i}^{E}) + (C_{grid,i}^{G} \times P_{grid,i}^{G})] \qquad (1)$$

where C is the daily operational cost; $C_{grid,i}^{E}$, $C_{grid,i}^{G}$ are electricity and gas unit costs at hour *i*; and $P_{grid,i}^{E}$, $P_{grid,i}^{G}$ are the power inputs to the energy system from the electricity and gas networks at hour *i*.

A scenario consisting of electricity supply from the external grid and gas supply to the CHP unit to produce both heat and electricity is considered as the base case (see Fig. 1). An optimisation algorithm (see Section 2.3) decides the most economic mix of gas and electricity intake at every hour. To assess the flexibility provision of energy stores, TES and EES units are incorporated into the base case (see Fig. 2). The optimisation algorithm for the retrofitted IES is updated with additional equations to determine the optimal sizes of the energy stores which would minimise operational costs.

The retrofitted IES essentially requires optimisation in two aspects: 1) to find the appropriate mix of gas and electricity to feed into the system at hourly intervals and, 2) to find the charging/discharging of the energy stores at every hour to achieve demand-side management. The formulation of the objective function to account for these two aspects is presented in Section 2.3.

The assumptions considered in the system modelling are as follows:

(i) For the CHP unit, the gas to electricity conversion efficiency is 0.36 and the gas to heat conversion efficiency is 0.58.

(ii) There are no stand-by energy losses from the energy storage components.

The optimisation algorithm was developed in MATLAB 2021b. To verify its capabilities, it was initially assessed using a test system consisting of an electrical transformer, a CHP unit, and a TES tank as presented in [2], alongside the energy price and demand inputs reported in the same paper. The optimal daily operational cost reported in [2] is 616 monetary units, which is in good agreement with the optimal cost of 610 monetary units obtained with the algorithm presented in Section 2.3.

To provide further confidence into the optimisation methodology, the operation of an IES considering a CHP unit, a TES system, and an EES system (i.e. considering similar technologies as in the system under study shown in Fig. 2) was optimised with the presented algorithm and the results are compared to those shown in [11]. The daily operational cost reported in [11] is €3413, while the cost obtained here is €3240. This difference of 5% in the results ratifies the applicability of the algorithm presented in this paper.

2.3 Optimisation algorithm

Its goal is to minimise the daily operational cost of the energy system under study. However, the size of the energy storage units is an important consideration due to the general space and financial constraints for accommodating additional components into the IES. The objective function is therefore formulated to minimise daily operational cost plus a penalty cost of the total amount of energy charged and discharged into the storage components throughout the cycle:

$$C_m = \sum_{i=1}^{24}\left[\left(C_{grid,i}^{E} \times P_{grid,i}^{E}\right) + \left(C_{grid,i}^{G} \times P_{grid,i}^{G}\right)\right] + P \times \sum_{i=1}^{24}\left[\left(P_{ch,i}^{TES} + P_{dis,i}^{TES}\right) + \left(P_{ch,i}^{B} + P_{dis,i}^{B}\right)\right] \quad (2)$$

A suitable value of the penalty parameter was determined heuristically as 9×10^{-5}. The penalty term in (2) ensures that the optimisation algorithm yields the minimum energy storage component size, while several different sizes of energy store retrofits can result in the same minimum daily operational cost of the system.

The constraints of the optimisation problem are defined as follows:

$$P_{grid,i}^{E} + \eta_{CHP}^{g/e} P_{CHP,i}^{G} \geq P_{d,i}^{E} \quad \text{(Electricity demand for CHP only hub)} \quad (3)$$

$$\eta_{CHP}^{g/h} P_{CHP,i}^{G} \geq P_{d,i}^{H} \quad \text{(Heat demand for CHP only hub)} \quad (4)$$

$$P_{grid,i}^{E} + \eta_{CHP}^{g/e} P_{CHP,i}^{G} \geq P_{d,i}^{E} \quad \text{(Electricity demand for CHP with TES)} \quad (5)$$

$$\eta_{CHP}^{g/h} P_{CHP,i}^{G} - P_{ch,i}^{TES} + P_{dis,i}^{TES} \geq P_{d,i}^{H} \quad \text{(Heat demand for CHP with TES)} \quad (6)$$

$$P_{grid,i}^{E} + \eta_{CHP}^{g/e} P_{CHP,i}^{G} - P_{ch,i}^{B} + P_{dis,i}^{B} \geq P_{d}^{E} \quad \text{(Electricity demand for CHP with battery)} \quad (7)$$

$$\eta_{CHP}^{g/h} P_{CHP,i}^{G} \geq P_{d}^{H} \quad \text{(Heat demand for CHP with battery)} \quad (8)$$

$$P_{grid,i}^{E} + \eta_{CHP}^{g/e} P_{CHP,i}^{G} - P_{ch,i}^{B} + P_{dis,i}^{B} \geq P_{d}^{E} \quad \text{(Electricity demand for CHP with TES and battery)} \quad (9)$$

$$\eta_{CHP}^{g/h} P_{CHP,i}^{G} - P_{ch,i}^{TES} + P_{dis,i}^{TES} \geq P_{d,i}^{H} \quad \text{(Heat demand for CHP with TES and battery)} \quad (10)$$

The constraints in (3)-(10) dictate that the thermal and electrical energy supplied at every hour cannot be smaller than the respective demands in that hour.

Constraints for the energy storage components are defined as:

$$\sum_{i=1}^{24} P_{ch,i}^{TES} - P_{dis,i}^{TES} = 0 \quad (11)$$

$$\sum_{i=1}^{24} P_{ch,i}^{B} - P_{dis,i}^{B} = 0 \quad (12)$$

Equations (11) and (12) are used to declare that over a diurnal cycle the total energy charged into the TES and EES units is equal to the total energy discharged from the stores. This ensures the cyclic operation of the storage components without any eventual accumulation or depletion of stored energy over time.

The following constraints represent the upper and lower bounds of the variables to be optimised:

$$0 \leq P_{grid,i}^{E}, P_{CHP,i}^{G} \leq 9999 \quad (13)$$

$$0 \leq P_{ch,i}^{TES} \leq 1000 \quad (14)$$

$$0 \leq P_{dis,i}^{TES} \leq 1000 \quad (15)$$

$$0 \leq P_{ch,i}^{B} \leq 200 \quad (16)$$

$$0 \leq P_{dis,i}^{B} \leq 200 \quad (17)$$

where the lower bounds for both electricity and gas consumption are assigned to 0, as shown by (13), as the capability to export surplus electricity to the external grid is not assumed as possible. For simplicity, the upper bounds of gas and electricity consumption are assigned to large values to let the optimisation algorithm explore all feasible combinations of gas and electricity to be consumed every hour. To control the rate of charging/ discharging of the TES and EES units, their upper and lower bounds are given in (14)-(17).

With the objective function and the constraints defined in Equations (2)-(17), the optimisation problem is solved using the *fmincon* function in MATLAB [20]. The sequential quadratic programming algorithm and 10^6 iterations are used. The solver settings were adopted after assessing the performance of the algorithm with the examples discussed by the end of Section 2.2.

3. RESULTS AND DISCUSSION

The optimisation model presented in Section 2.3 enables to find the optimal proportions of energy resources to be consumed throughout the daily cycle of the IES under study. Additionally, the energy interactions of the storage retrofits and their respective sizes were determined using the optimisation algorithm.

Considering a gas unit price of £0.02 and the electricity price profile in Fig. 3, the IES was evaluated under four different scenarios: 1) base case without any storage, 2) CHP plant with TES unit, 3) CHP plant with EES unit, and 4) CHP plant with both TES and EES units. The charging and discharging efficiency of the TES unit was considered as 0.9 [2], and for the EES unit as 0.98 and 0.96 for charging and discharging, respectively [21]. The corresponding gas and electricity consumption profiles and the daily operational costs are shown in Fig. 5.

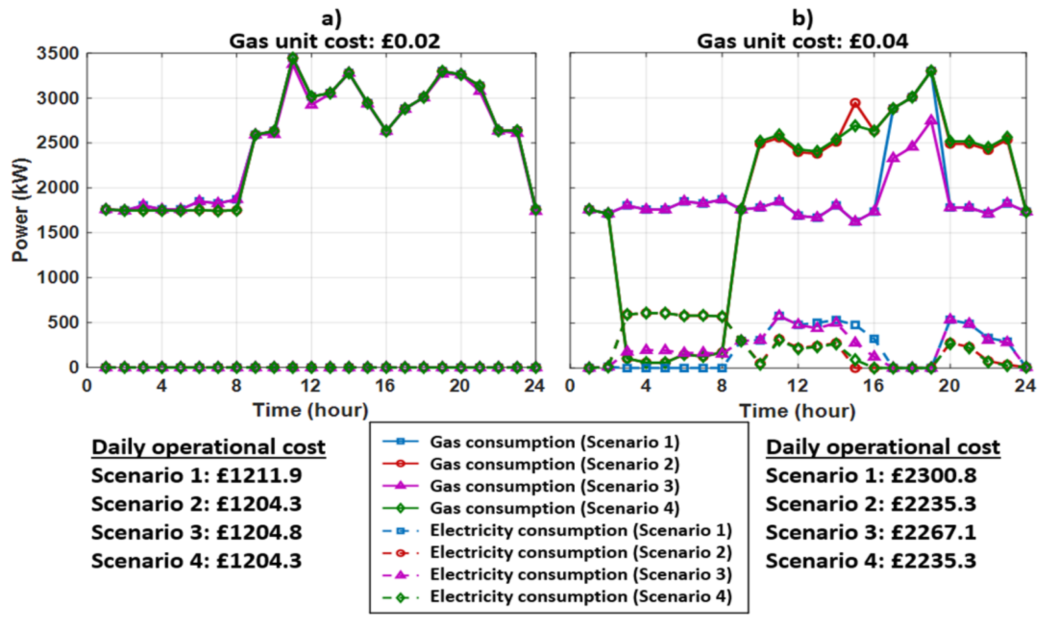

Fig. 5 Optimal power intake profiles and daily operational costs.

Given the significantly lower price of gas (£0.02) compared to that of electricity, the optimisation algorithm suggests using entirely the CHP plant to meet both heat and electricity demand, without drawing electricity from the grid in any of the four scenarios. The addition of energy stores into the IES allows for temporal adjustments of energy loads and thereby assists in demand-side management.

Incorporation of the TES unit (scenario 2) achieves the maximum reduction in operational cost (from £1211.9 to £1204.3) from the base scenario 1. Although the EES unit can achieve a similar drop in operational cost when used as a standalone energy storage component (scenario 3), it is made redundant when both TES and EES units are incorporated into the IES (scenario 4). Fig. 6a demonstrates the EES redundancy through the energy levels of the TES and the EES units: while the TES unit operates throughout the diurnal cycle, the EES unit remains idle. This is also reflected in the total operational cost of scenario 4 which is the same as in scenario 2.

Fig. 6a also indicates that a TES unit with a capacity of 250 kWh would be required as this is the maximum energy that needs to be stored during the cyclic operation. The same energy levels of the TES unit are also obtained in scenario 2. Similarly, if the EES unit is used as the storage component only (scenario 3), then a capacity of 135 kWh would be required.

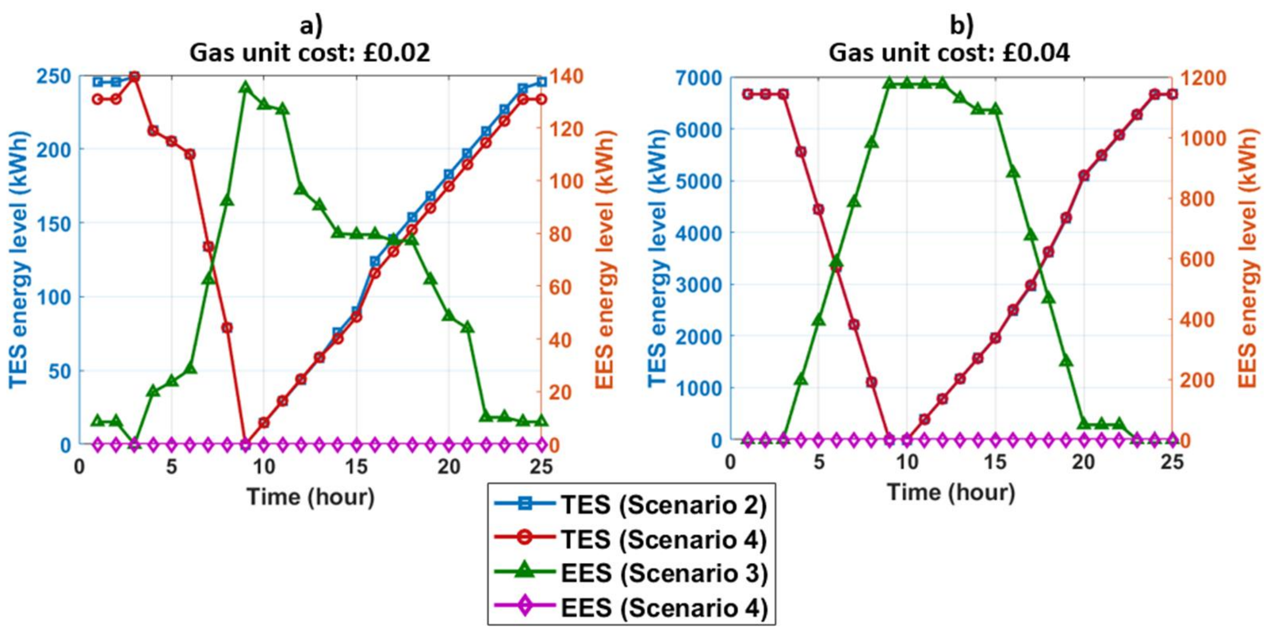

Fig. 6 TES and EES energy levels.

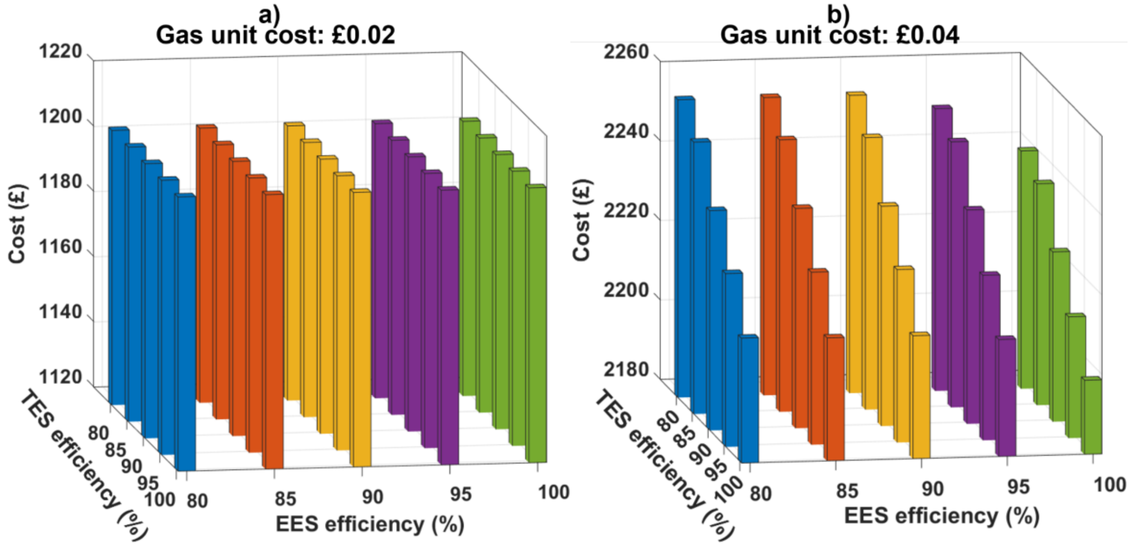

Fig. 7 Daily operational costs for different storage retrofit efficiencies.

To assess the impact of sudden gas shortages, the gas price was increased to £0.04 while keeping the electricity price profile the same (see Fig. 3) and the four scenarios were re-evaluated. The corresponding gas and electricity consumption profiles and daily operational costs are shown in Fig. 5b.

With the increased gas prices, the IES draws electricity from the grid at certain hours while gas intake still dominates the overall energy imports. Just as when the cost of gas was assumed as £0.02, the IES attains the maximum operational cost savings in scenarios 2 and 4 (from £2300.8 in the base scenario 1 to £2235.3) by including a TES unit with a capacity of 6667 kWh. An EES unit-only deployment would require a storage capacity of 1176 kWh (scenario 3). From the daily operational cost viewpoint, if either a TES unit or an EES unit is to be selected as the single storage option, incorporating a TES unit would still be more beneficial (£2235.3 operational cost) over the EES unit (£2267.1).

To probe further into the analysis of the IES, the effects of the charging/discharging efficiencies of the energy stores were assessed in terms of possible changes in the optimal operating cost and required sizes of the storage units. To this end, the charging/discharging efficiencies of both storage components were varied from 80% to 100% in intervals of 5% to assess the changes in the IES performance.

Fig. 7 shows that for the nominal profiles of gas price (£0.02) and electricity price (see Fig. 3), the optimal operational cost does not change for the different efficiencies of the storage components (Fig. 7a). This shows that the retrofitted IES is flexible enough to accommodate the considered efficiency variations of the storage components while retaining the cost optimality.

The capacity of the energy storage retrofits is shown in Fig. 8. The EES unit is not used for any efficiency below 100% (represented with zero capacity in Fig. 8a). TES overall dominates the storage operations for the IES,

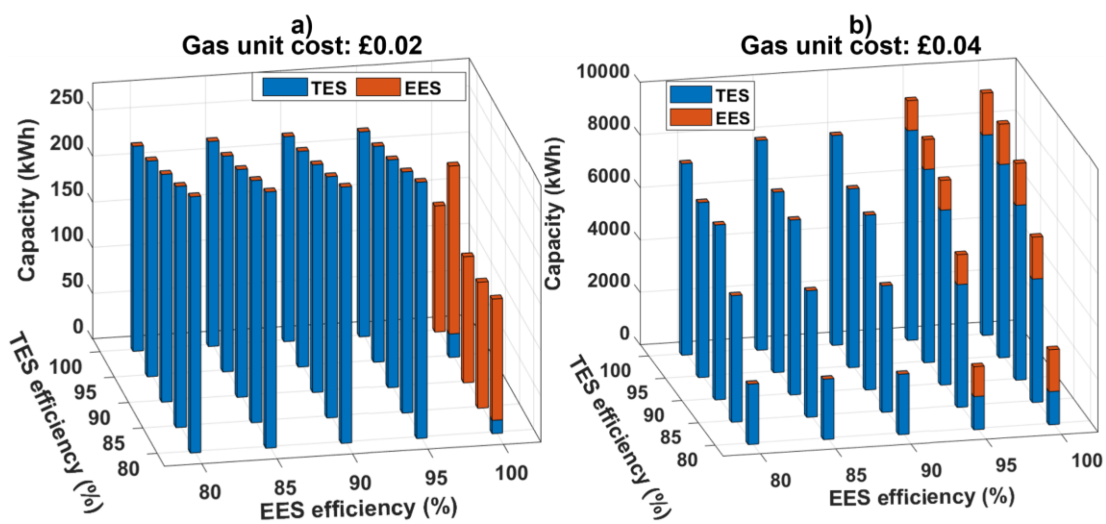

Fig. 8 Capacity of storage retrofits.

with only a few cases where the EES unit is used alongside the TES unit.

Upon increasing the gas cost to £0.04, the changes in the optimal cost become noticeable with variations in charging/discharging efficiencies. The daily operational cost is more sensitive to TES charging/discharging efficiency compared to those of the EES unit. For the EES unit, no change in operational cost is observed for efficiencies below 90% as it is made redundant by the optimiser (reflected in Fig. 8b with zero EES capacity). With increments above 90% efficiency, an EES unit with a larger capacity becomes desirable.

As for the TES unit, the optimisation algorithm prefers its use even with a low 80% charging/discharging efficiency (unlike the case of EES). This emphasizes the importance of a TES system in the IES under study. With every increment in TES charging/discharging efficiency, an optimised network operation would result with a larger storage capacity to realise additional operational cost saving.

By comparing Fig. 8a with Fig. 8b, it is further noticed that the IES requires a TES unit with substantially larger capacity for demand-side management when the gas price is doubled. These findings illustrate that the IES could capitalise more from the addition of TES into the network to enhance its resilience—particularly in situations of unplanned gas price surcharges.

4. CONCLUSIONS

This paper presented the optimal selection, schedule and sizing of energy storage retrofits into an existing IES. The system under study was replicated from real-time data sourced from a UK-based public facility dedicated to health services. Coupling energy storage retrofits into the IES enabled favourable shifts in the energy transactions that resulted in operational cost savings.

For the system under study, the addition of a TES unit was more lucrative than incorporating an EES unit both under regular pricing conditions and during gas price increments. An optimally sized TES unit of 250 kWh capacity yielded an operational cost saving of £7.6/day with a regular gas unit price of £0.02. On the other hand, the optimal capacity of the TES unit was found to be 6667 kWh to derive an operational cost saving of £64.7/day when the gas unit price was raised to £0.04. Unforeseen events such as the gas price increase dictate the requirement for a larger storage capacity, implying that bigger opportunities emerge for demand-side management as energy prices rise.

The scenarios included in the paper while considering contemporary energy market layouts suggest that the quantity of energy consumption is as important as when and in which form it is consumed by the IES—all of which can be determined by the optimal scheduler presented in the paper.

Future research work could investigate broader time horizons to schedule the operation of the retrofitted IES. Furthermore, the system operation could be tested with different energy demand profiles to consider seasonality and other geographical locations. This could contribute to improve the day-to-day energy utilisation of similar IESs and alleviate strenuous situations of fuel shortages.

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