Calculating system integration costs of low-carbon generation technologies in future GB electricity system

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Abstract

System integration costs (SIC) of generation technologies, also referred to as system externalities, include various categories of additional costs that are incurred in the system in addition to the cost of building and operating the generation capacity that is added to the system. SIC may include increased balancing cost, cost of additional backup capacity, cost of reinforcing network infrastructure and the cost of maintaining system carbon emissions. In this paper we present a whole-system approach to quantifying the SIC and explore different approaches to calculating the relative SIC of a generation technology when compared to another technology. The results show that the SIC of low-carbon generation technologies will significantly depend on the composition of the generation mix, with higher penetrations of variable renewables giving rise to a higher SIC. Also, SIC will significantly depend on the deployment level of flexible options such as more flexible generation technologies, energy storage, demand side response or interconnection. The additional system cost driven by low-carbon technologies can provide a very useful input to inform the energy policy and support the selection of the low-carbon portfolio with the lowest total system cost.

1. Introduction

Understanding and quantifying the *system integration costs* (SICs) of various low-carbon generation technologies (LCGTs) is critically important in the context of the expected future decarbonisation of the British electricity system in line with the ambitious decarbonisation targets in the 2050 horizon [1]. SICs of generation technologies (also sometimes referred to as *system externalities*) include various types of costs that are imposed on the system by added generation capacity, but which are not included in the capital or operating cost estimates of these technologies. Examples of SIC components include:

- *Increased balancing cost* associated with: a) increased requirements for system reserve due to higher uncertainty of variable renewable generation output, and b) increased requirements for fast frequency regulation (response) due to reduced system inertia.
- *Network reinforcements* required in interconnection, transmission and distribution infrastructure (e.g. transmission reinforcement to connect remote wind resources or distribution network upgrade to cope with increased reverse power flows triggered by high volume of distributed solar PV installations).
- *Increased backup capacity cost* due to limited ability of e.g. variable renewable technologies to displace "firm" generation capacity needed to ensure adequacy of supply.
- *Cost associated with the mismatch* between the technology's generation profile and the demand profile (e.g. solar PV output peaks in summer, while peak demand in the GB system occurs in winter).
- *Cost of maintaining system carbon emissions*, as the addition of certain technologies may cause the overall emission performance of the system to deteriorate, requiring that additional low-carbon capacity is installed to maintain the same level of carbon emissions.

The quantification of SICs in addition to the cost of building and operating low-carbon generation capacity, i.e. their Levelised Cost of Electricity (LCOE), therefore represents a critical input into planning for a cost-effective transition towards a low-carbon electricity system, enabling the development of policies and support mechanisms that consider both private and wider system costs of different technologies.

The concept of integration cost, in particular in the context of expanding renewable generation, has been receiving attention for well over a decade [2],[3]. One possible approach to quantify SIC is to calculate each of its components (balancing, network or backup capacity) separately, as for instance in [4] or [5], however this approach can potentially miss the interaction between different cost components. The approach proposed in [6] defines integration costs based on the marginal economic value of electricity, and decomposes SIC of wind and solar power into three components: temporal variability, uncertainty, and location constraints. The importance of flexibility as a means of managing SIC of renewable technologies has been recognised in a number of studies ([7],[8]), although the quantification of this impact has not been comprehensively addressed.

In this paper a whole-system assessment approach elaborated in [9] has been applied to simultaneously quantify the additional system cost driven by expansion of LCGTs across the entire electricity system, including both operating cost and investment into generation and network infrastructure. In a system with high proportion of variable renewables, it is important to assess SIC from a whole-system perspective using high time and spatial resolution.

The analysis presented in this paper is based on the recent study carried out for the Climate Change Committee [10].

2. Methodology for calculating system integration cost

Most of the previous approaches to quantifying SICs focused on quantifying individual components of SIC. All of these methods calculated the *absolute integration cost* i.e. the cost associated with a single technology that is added to the system. Nevertheless, there is at present no commonly accepted method to quantify SIC, as different definitions have their own issues with robustness or accuracy.

In this paper we adopt several definitions that focus on the *relative integration cost* reflecting the difference between the system externalities of pairs of LCGTs. This approach ensures a robust calculation approach while at the same time indicating relative merits of different LCGTs from the whole-system perspective. In the studies presented in the paper nuclear power is selected as the counterfactual LCGT, against which the relative SIC of other LCGTs (wind, solar and CCS) are quantified. The choice of nuclear as the benchmark technology is somewhat arbitrary; however, this choice does not affect the differences between relative SICs quantified for other LCGTs (such as e.g. between the SICs of wind and PV generation).

2.1. Whole-system assessment of electricity systems

Different components of SIC are incurred in different segments of the electricity system, such as generation, transmission or distribution infrastructure, or are a part of system operation and balancing cost. Therefore, the quantitative framework applied to evaluate the SIC is based on the whole-system modelling approach i.e. the WeSIM model elaborated in [9]. This model has the ability to simultaneously make investment and operation decisions with high (hourly) time resolution, while capturing the interactions between different time scales (investment vs. short-term operation) as well as across different asset types in the electricity system (e.g. generation vs. network). At the same time the model can also consider various flexible technologies such as energy storage or demand-side response (DSR). A distinct characteristic of the model is the ability to capture and quantify the necessary investments in distribution networks in order to meet demand growth and/or distributed generation uptake, based on the concept of statistically representative distribution networks. A detailed description of the model can be found in [9].

In this study the WeSIM model was applied to the interconnected GB electricity system that was represented with four transmission nodes within GB and two neighbouring systems: Ireland and Continental Europe (CE), with the latter representing the entire interconnected European system. In order to simulate cost-efficient outcomes across Europe, the model was set up to optimise the operation of the entire European system, taking into account interconnection capacities between systems. Two further important features endogenously included in the model are the capability to impose a given carbon emission constraint for each system, as well as ensure sufficient generation capacity is built in each system to meet the security of supply standards.

2.2. Valuation of flexible options in future systems

As part of the whole-system assessment framework employed in this analysis, there are four main categories of flexible options that were considered: (i) demand-side response (DSR), (ii) flexible generation technologies, (iii) network solutions such as investing in interconnection, transmission and/or distribution networks, and (iv) the application of energy storage technologies. Details on how these different flexible options have been included in the whole-system modelling framework can be found in [10].

A previous study by the authors [11] found that in the absence of alternative flexible balancing technologies the scale of the balancing challenge in the future GB electricity system would increase very significantly beyond 2030, with substantial investment needed in additional generation, transmission and distribution assets to achieve the carbon emission targets while ensuring security of supply. Lack of flexibility significantly limits the system's ability to integrate high volumes of variable renewable energy sources (VRES): the same study demonstrated that up to 30% of electricity theoretically available from VRES may need be curtailed in 2050 if no flexible options are deployed. VRES curtailment may become necessary to balance the system, e.g. during periods of low demand, high renewable output, and high output of must-run units such as nuclear plants, or conventional generators that have to be synchronised in order to provide ancillary services. Curtailment of VRES will obviously have an adverse impact on the carbon intensity of electricity supply given that the system effectively spills zero-carbon renewable output.

It is therefore essential to study various system flexibility levels as one of the key determinants of the system's ability to cost-effectively integrate VRES generation. Flexibility is hence included as a key parameter in subsequent SIC studies as it is evident that flexibility can greatly reduce the SIC of VRES, particularly in future development scenarios with high shares of renewable generation.

2.3. Methods for calculating SIC

The *whole-system cost* (WSC) of any generation technology can be expressed as the sum of the LCOE of that technology and the corresponding SIC:

$$WSC_{gen} = LCOE_{gen} + SIC_{gen} \tag{1}$$

Terms in (1) are typically expressed in monetary units per unit of energy produced (e.g. in £/MWh). All generation technologies will potentially have a SIC although for some technologies and systems this value may become negative (i.e. the technology may provide a system integration benefit). There is currently no widely accepted consensus regarding the exact definitions of various components of SIC and their interactions, and the methods for evaluating and allocating these costs vary considerably.

In contrast to the approaches that quantify the components of SIC separately, such as e.g. by considering only additional balancing or additional network cost without looking at their interaction, this paper quantifies the whole-system impact of adding a unit of LCGT in a given system scenario while maintaining a given carbon intensity target. The approach presented here quantifies each of the components of SIC that result from the system cost-optimally adapting to the addition of LCGT across all cost categories. As an example, if there is a significant volume of DSR present in low-voltage (LV) distribution grid, and wind capacity is being added to the system requiring a higher volume of balancing services to be provided, it may be opportune to invest into reinforcing the distribution network in order to enable the system to access flexible DSR resource at the distribution level so that this flexibility can be used to reduce balancing cost at the national level. These interactions and trade-offs would be highly difficult to capture when quantifying SIC components separately.

In terms of the allowed response of the system to the addition of a unit of LCGT, we distinguish between three different methods to quantify the Relative Integration Cost (RIC), while adopting nuclear power as the benchmark LCGT. The relationship between the relative SIC of technology 1 compared to technology 2, their WSCs and LCOEs can be expressed as follows:

$$RIC_{1-2} = WSC_1 - WSC_2 - (LCOE_1 - LCOE_2) \qquad (2)$$

The following three SIC calculation methods have been applied in this paper:

- *Method 1 (Fixed Replacement)*
  In this approach 1 GW of nuclear capacity is removed from the system, while an energy-equivalent amount of offshore wind (2.1 GW), PV (9 GW) or CCS capacity (1 GW) is added to the system. Energy equivalence here means that the removed and added capacities are capable of providing the same nominal annual output (e.g. if the annual utilisation of nuclear is 90% and that of offshore wind is 43%, then it would take about 2.1 GW of wind capacity to produce the same output as 1 GW of nuclear). In all SIC studies the model re-optimises the system and determines the capacities of conventional generation, while at the same time enforcing the same level of carbon intensity as in the original system; this can be achieved by adding CCS capacity above the base case level if necessary. Changes in total system cost, excluding the investment and operation cost (i.e. LCOE) of the pairs of technologies involved in the substitution, are divided by the annual output of the added low-carbon technology to establish its relative SIC against nuclear power in £/MWh.
- *Method 2 (Optimised Replacement)*
  With this method, when 1 GW of nuclear capacity is removed from the system, instead of adding a pre-specified capacity of another LCGT the model is allowed to optimally increase the capacity of that technology, while at the same time maintaining the same overall GB system emissions. No change in CCS capacity is allowed in this method; the model is only allowed to adjust conventional capacity if cost-efficient. Changes in total system cost are again divided by the increase in generation output (as in Method 1) to find out the relative integration cost; however, with Method 2 the cost of LCGT capacity added in excess of the energy-equivalent volume is also taken into account when finding the total cost differential between the original system and a given SIC study.
- *Method 3 (Difference in Marginal Benefits)*
  In this method a moderate amount of nuclear, wind, PV or CCS capacity is added to the system, while allowing the system to readjust its CCS capacity (or nuclear if CCS is added) as well as any conventional capacity in a cost-optimal fashion while maintaining the same system emissions as in the base case. The reduction in total system cost (while ignoring the CAPEX and OPEX of the added low-carbon technology) is divided by the additional output of the added technology to establish the *marginal system benefit* per MWh for that technology. The difference between the marginal benefit of e.g. nuclear and wind then allows for an implicit quantification of the relative system externality of wind compared to nuclear, providing a comparable result with Methods 1 and 2.

Table 1 compares the key elements of the three calculation methods for system integration cost.

Method	Technology added	Technology removed	Adjusted capacity
Method 1	Wind (fixed)	Nuclear (fixed)	CCS, CCGT, OCGT
	PV (fixed)	Nuclear (fixed)	CCS, CCGT, OCGT
	CCS (fixed)	Nuclear (fixed)	CCGT, OCGT
Method 2	Wind (opt.)	Nuclear (fixed)	CCGT, OCGT
	PV (opt.)	Nuclear (fixed)	CCGT, OCGT
Method 3	Nuclear (fixed)	CCS (opt.)	CCGT, OCGT
	Wind (fixed)	CCS (opt.)	CCGT, OCGT
	PV (fixed)	CCS (opt.)	CCGT, OCGT
	CCS (fixed)	Nuclear (opt.)	Nucl, CCGT, OCGT

Table 1: Comparison of different SIC calculation methods

Note that in all of the SIC studies the additions and removals of LCGT capacities imposed on the GB system are relatively substantial rather than marginal quantities. This was necessary for computational reasons, in order to ensure the results are numerically robust given that the optimisation is carried out for the entire European system with more than 1,000 GW of installed generation capacity.

3. Case studies

3.1. Scenarios and assumptions

SIC of LCGTs in this paper is evaluated across three main scenarios for the 2030 GB system that are designed to achieve a given level of power system decarbonisation:

- 100 g/kWh
- 50 g/kWh (wind-dominated)
- 50 g/kWh (solar-dominated)

The three scenarios include different mixes of LCGT capacity (nuclear, wind, solar PV and CCS) in the GB system, as summarised in Table 2. A comparably ambitious deployment of LCGTs has also been assumed in Irish and CE systems (see e.g. [12]).

Technology	100 g/kWh	50 g/kWh (wind-dominated)	50 g/kWh (solar-dominated)
Nuclear	9.6	10.6	10.6
CCS	7.1	7.7	7.7
Wind	36.0	53.0	45.4
Solar PV	20.0	20.0	50.0

Table 2: LCGT capacity assumptions (in GW) across scenarios

Although these LCGT mixes would be theoretically adequate to achieve the specified emissions intensity targets purely based on the expected annual energy outputs, they do not consider real-time system operation requirements such as e.g. balancing short-term fluctuations in demand and VRES output and maintaining overall system security. When these generation mixes were initially tested with the WeSIM model, it was found that the outturn emissions intensity could be very significantly higher than the target level unless the flexibility of the system is improved. A combination of low demand, high VRES output, and high output of must-run units such as nuclear plants, or conventional generators that have to be synchronised in order to provide frequency regulation will have an adverse impact the carbon intensity of the electricity system (as VRES output may need to be curtailed and the conventional plant output increased).

Therefore, to support an effective integration of low-carbon electricity, a number of flexible options were assumed to exist in the three system scenarios:

- *More efficient and more flexible generation technologies*: conventional plant that can operate stably at lower levels of output and provide faster frequency response.
- *Reduced primary frequency regulation requirements and improved system management and forecasting techniques* leading to reduced requirements for reserve and secondary response services. It is also assumed that by 2030, VRES generators (e.g. wind farms) would be capable of contributing to reserve services when curtailed.
- Deployment of 5 GW of additional *energy storage* capacity that can deliver ancillary services (e.g. reserve and response) in addition to energy arbitrage, provision of back-up capacity and deferral of network reinforcement.
- *DSR* that is capable of performing demand shifting and providing ancillary services and network congestion management. The assumed uptake level of DSR in the study (compared to total assumed technical potential) was 50%, and consisted of flexible heating, transport, residential and commercial loads.
- Increased *interconnection* with mainland Europe; in addition to 4 GW of existing interconnection capacity, it was assumed that 3.4 GW of additional capacity will be added by 2030 to connect GB with France, Belgium and Norway.

All assumptions regarding flexibility were made taking into account the realistic technical potential for deploying these options in GB in the 2030 horizon. More detailed assumptions on different flexibility options, as well as assumptions on other parameters such as fuel and carbon prices, can be found in [10]. The costs of LCGTs in the 2030 horizon have been assumed as follows (expressed on LCOE basis): nuclear £89/MWh, CCS £100/MWh, offshore wind £85/MWh and solar PV £69/MWh.

Starting from generation mixes in Table 2 and the assumed level of system flexibility, the WeSIM model was used to determine the conventional plant (CCGT and OCGT) required to meet electricity demand, maintain security of supply and ensure sufficient volume of reserve and response services. Scenarios thus obtained are adopted as counterfactuals for subsequent SIC studies.

3.2. System integration cost across different scenarios

As described in Section 2.3, the SIC studies are set up so that the capacity of one LCGT is increased while the capacity of another (nuclear) is reduced, while meeting the system-wide carbon target.

In the 100 g/kWh scenario (Figure 1) the SIC of wind and PV (compared to nuclear) are relatively modest, in the range of £6-9/MWh. A relatively lower deployment of wind and PV in this scenario combined with the presence of flexible options results in very low renewable curtailment when adding incremental wind and PV capacity. Therefore there is no need to install additional CCS capacity to compensate for spilled low-carbon output and maintain the same carbon emissions.

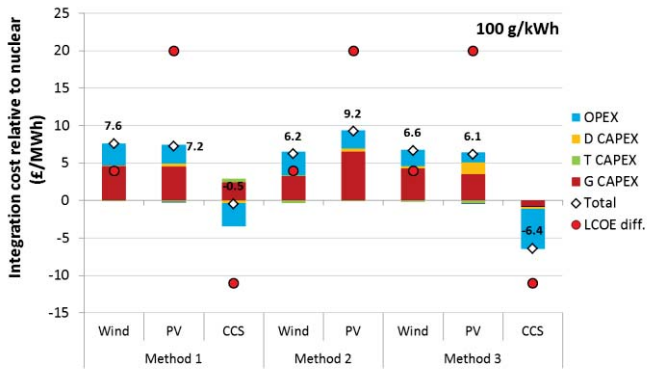

Figure 1: SIC of LCGTs in 100 g/kWh scenario

The generation investment (G CAPEX) component of SIC for wind and PV is mainly associated with an increased need for backup capacity, while the additional operating cost (OPEX) results from increased volumes of ancillary services causing lower operational efficiency of conventional generation.

To provide a whole-system cost comparison between LCGTs, Figure 1 also indicates the differences in assumed LCOEs between a given technology and nuclear ("LCOE diff."), which are expressed as cost advantages of LCGTs against nuclear. This allows for a quick comparison: if the LCOE difference is lower than the SIC for a given LCGT, its whole-system cost will be higher than that of nuclear, and vice versa.

As an example, according to Method 1 removing 1 GW of nuclear and adding 2.1 GW of offshore wind capacity leads to an increase in system costs of £7.6/MWh of wind output, provided that carbon emissions are maintained at 100 g/kWh. As the assumed difference in LCOE between nuclear and wind is £4/MWh, replacing nuclear with wind will lead to a net increase in system cost of £3.6/MWh of wind output. On the other hand, as the LCOE of PV is assumed to be £20/MWh lower than nuclear, replacing nuclear with PV according to Method 1 will result in a net reduction in system cost of £12.8/MWh of PV output.

The net increase in system cost when nuclear is replaced with wind (£3.6/MWh) suggests that the system would benefit from substituting wind with nuclear capacity i.e. that the installed capacity of wind is above, and of nuclear below the optimal deployment volume where the sum of LCOE and integration costs of all technologies should be equal. Similarly, the net decrease in total system cost when PV replaces nuclear capacity suggests that the system would benefit from adding more solar PV capacity.

Finally, the SIC of CCS varies between broadly zero and minus £6/MWh; negative SIC (effectively system integration benefit) indicates that due to higher flexibility there is a positive externality associated with the replacement of a unit of nuclear with CCS (ignoring the LCOEs of the two technologies).

The wind-dominated 50 g/kWh scenario features a higher volume of wind capacity (53 GW), and as shown in Figure 2, this results in SIC values of £12-17/MWh, which is significantly higher for both wind and PV than in the 100 g/kWh scenario. The key SIC components come from:

a) Increased generation CAPEX, driven not only by backup capacity requirements, but also by additional CCS or wind or PV capacity required to maintain grid carbon intensity given that a part of additional wind/PV output may need to be curtailed and/or that the additional ancillary service requirements may reduce the efficiency and increase emissions of thermal generation; and

b) Increased OPEX, again due to higher output from CCS plants to compensate for curtailment of zero-carbon VRES generation.

The composition of the integration cost of CCS differs depending on the calculation method used. A like-for-like replacement of 1 MWh of output of nuclear with CCS would on its own result in increased emissions due to less than 100% carbon capture rate of CCS. For this reason the replacement of nuclear with CCS in Method 1 triggers the reinforcement of North-South transmission corridors (hence the considerable T CAPEX component) in order to reduce wind curtailment in the North and thus improve system carbon emissions (note that no addition of low carbon capacity was allowed). In Method 3, however, the retirement of nuclear capacity following the addition of 1 GW of CCS is optimised, which results in only 0.9 GW of nuclear being removed from the system while maintaining the same emissions. The remaining CCS output displaces CCGT generation, with further positive impact on OPEX and carbon emissions, resulting in lower T CAPEX requirements to reinforce transmission grid to transport wind from the North.

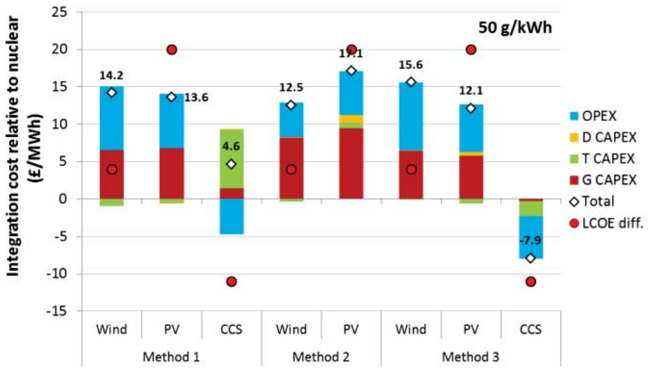

Figure 2: SIC of LCGTs in wind-dominated 50 g/kWh scenario

In the solar-dominated 50 g/kWh scenario, which features a much higher PV capacity (50 GW instead of 20 GW), the SIC of PV becomes significantly higher at £26-£28/MWh, as shown in Figure 3. At the same time the SIC of wind is the same or even slightly lower than in the wind-dominated 50 g/kWh scenario.

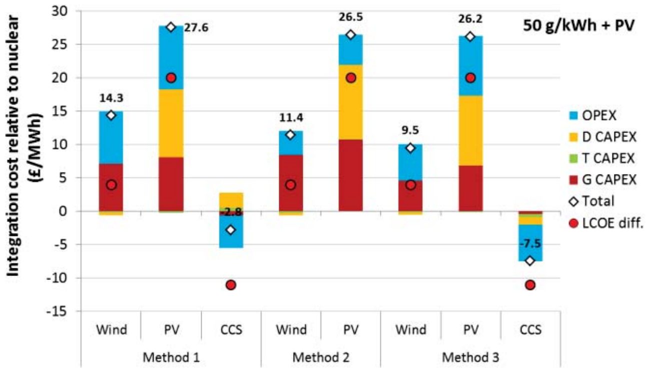

Figure 3: SIC of LCGTs in solar-dominated 50 g/kWh scenario

In this scenario there is again significant curtailment of VRES output, requiring additional CCS capacity and driving the additional G CAPEX and OPEX components of wind and PV integration cost as before. Unlike in the wind-dominated scenario, the SIC of PV now features a substantial distribution investment (D CAPEX) component at the level of around £10/MWh, which is driven by reinforcements triggered by increased reverse power flows in the GB distribution grid. High PV capacity would generate significant reverse power flows due to solar PV injecting energy into the distribution grid that currently only handles energy flowing from transmission grid towards consumers.

3.3. Impact of flexibility on SIC

An additional set of sensitivity studies analysed the impact of variations in system flexibility on the SIC of wind and PV in the three scenarios. The Medium flexibility level (Mid Flex) corresponds to the central set of assumptions on DSR and storage (50% DSR uptake and 5 GW of new storage). Low flexibility assumes a system without any additional storage or DSR, while High flexibility case assumes 100% uptake level of DSR, 10 GW of additional storage and wind being able to contribute to both response and reserve when curtailed.

Changes in SIC of wind an PV resulting from moving from Medium to Low or High flexibility are presented in Table 3 (all results in the table refer to SIC obtained using Method 1).

Enhanced system flexibility has a clearly positive impact on SIC of both wind and PV. The SIC of wind generation drops by about £5-8/MWh across the three scenarios as the result of improved flexibility, while corresponding benefits for PV are £1-5/MWh. On the other hand, reducing flexibility to the Low level increases the SIC dramatically, especially in the two 50 g/kWh scenarios, where the integration cost of wind increases by £27/MWh (almost three times) and that of PV by up to £73/MWh (almost four times), indicating a very limited ability of the system to integrate VRES generation.

Flexibility	**100 g/kWh**		**50 g/kWh (wind)**		**50 g/kWh (solar)**	
	Wind	**PV**	**Wind**	**PV**	**Wind**	**PV**
Low	7.7	11.3	26.6	29.3	26.7	73.1
High	-4.9	-1.6	-7.9	-5.3	-5.0	-0.8

Table 3: Changes in SIC of wind and PV resulting from modified system flexibility (Method 1, in £/MWh)

4. Conclusions

The three methods used to quantify SIC of LCGTs provide reasonably similar results. Slight variations between methods can be attributed to different approaches to re-adapting the system after adding a unit of a given LCGT.

In the three scenarios analysed, the SIC of wind and solar are relatively modest in a system achieving 100 g/kWh (ranging from £6-9/MWh), but these costs become more material when moving to a system achieving 50 g/kWh with high penetration of wind or solar, with costs up to £16/MWh for wind and £28/MWh for solar. This suggests that there may be limits or thresholds regarding the capacities of different LCGTs that the system can integrate cost-effectively; these limits will however be a function of system flexibility. The studies show that flexibility can significantly reduce the SIC of VRES (while a lack of flexibility significantly increases SIC), to the point where their whole-system cost makes them a more attractive choice than CCS and/or nuclear.

In a fully cost-reflective market all generation technologies would be exposed to additional costs (externalities) they impose on the system and would need to incorporate these costs in their market bids on top of their LCOEs. The market design in GB (as well as elsewhere in the world) is still evolving and is not yet necessarily fully cost-reflective in all aspects of SIC [13]. This analysis demonstrated that increasing system flexibility through improved conventional generation technologies and the application of energy storage, DSR and interconnection, can significantly reduce SIC of LCGTs, stressing the importance of developing efficient market mechanisms that would appropriately reward flexibility, thus facilitating a cost-effective decarbonisation of the GB electricity system.

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