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Long-run marginal CO_2 emissions factors in national electricity systems

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HIGHLIGHTS

- Quantification of electricity use CO_2 impacts via short-run emission factors is common.
- These short-run factors do not take account of structural change in a power system.
- Long-run marginal emission factors overcome this issue, and are defined and analysed.
- A new power system model is constructed and applied to study this issue.
- Long-run marginal emissions factor found to reduce to nearly zero from 2035 onwards.

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ABSTRACT

Estimates of the magnitude of CO_2 emissions reduction brought about by an intervention in the energy system are important because they signal which interventions are the most potent in terms of climate change mitigation. Yet quantifying emissions changes is not trivial because interventions act on the margin of the energy system, rather than acting on all components of the whole energy system equally. Therefore, in order to accurately attribute outcomes to interventions, the specific energy system changes precipitated by the intervention should be estimated, along with the corresponding change in emissions. This paper builds on previous research in this regard estimating short-run marginal emissions factors in national electricity systems. It presents the concept of the long-run marginal emissions factor (LR-MEF), and builds and applies a new electricity system model to study the problem. For the British electricity system it is found that the average LR-MEF is approximately 0.26–0.53 kg CO_2/kWh for the coming decade, but this reduces to approximately zero by 2035 and onwards as the system decarbonises. Furthermore, it is found that the LR-MEF can diverge very significantly from the short-run. This highlights the state of flux of the British electricity system and the importance of taking structural changes in the electricity system into account when attributing emissions reduction to interventions.

1. Introduction

Mitigation action remains a cornerstone of an effective response to climate change [1,2]. In order to limit the severity of future changes in climate, interventions will need to be focused and effective, achieving maximum reduction in greenhouse gas emissions and avoiding “lock-in” to technologies or infrastructures that could prevent realisation of long-term energy system decarbonisation [3]. In order for mitigation action to be this effective, energy system stakeholders need accurate and timely advice on the emissions reduction likely to be achieved by interventions in the energy system, over short and long timeframes. Such advice will enable targeted interventions, along with more directed R&D, demonstration and commercialisation of the most promising low carbon energy technologies.

Estimation of the emissions reduction brought about by the introduction of an energy technology into an energy system is not straight forward. This is true especially when that technology interacts with the electricity system. This is because the emissions reduction achieved in the electricity system are a function of which generators respond to a change in demand in the short-term, and which generators are commissioned or decommissioned (and how these are then operated) as a result of persistent changes in demand in the long-term. All too frequently abatement studies simply apply current system-average emissions factors to estimate abatement potential, which implicitly assumes that all components of the national electricity system respond proportionally to a demand change; an assumption that clearly is not correct. Furthermore, the use of system-average emissions factors also implies that the structure of the energy system is not expected to

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change over the lifetime of the intervention, which is another questionable assumption.

This final point above is the focus of the present article; what is the impact of additional demand in the electricity system on its structure and operation, and thus its long term contribution to greenhouse gas emissions? The metric chosen to enable assessment is the long-run marginal emissions factor (LR-MEF, defined below), which represents the long-term change in CO_2 emissions per unit change in demand, over the lifetime of a specific intervention.

Interest in this topic is motivated by the fact that electricity systems worldwide are expected to decarbonise rapidly if climate change mitigation targets are to be met [4–7]. Given such radical change is conceivably imminent, what are the correct emissions rates to use when assessing new technologies that interact with the electricity system? The primary intention of this paper is to develop a methodology to answer this question, with a secondary intention to apply the methodology to the case of the British electricity system.

The article is structured as follows. Firstly, after basic terminology is defined, a review of the background literature relevant to the research questions is presented, including an update on short-run marginal emissions factors as presented in [8]. This is followed by presentation of the methodology used to estimate the LR-MEF, and then description of development of a simple conceptual model to explore long-run marginal CO_2 emissions theory and potential ranges of outcomes. A new electricity system investment and operation model for the case of Britain is then presented, followed by application of this model to investigate the long-run marginal emissions factor associated with the electrification of heating in Britain. Finally, results and sensitivities are discussed, leading to a conclusion.

2. Definitions

A range of terminology is used in the electricity emissions intensity literature. Key terms and their definitions are as follows:

- *Average Emissions Factor (AEF):* The average CO_2 emissions per average unit of electricity delivered for an entire electricity system.
- *Operating Margin Emissions Factor (O-MEF):* The change in CO_2 emissions relating to a unit change in electricity demand, where there is assumed to be no structural change in the electricity system being analysed (i.e. no power station commissioning or decommissioning, no fuel price changes, etc.).
- *Short-Run Marginal Emissions Factor (SR-MEF):* The change in CO_2 emissions relating to a unit change in electricity demand, where there is usually little structural change in the electricity system being analysed. SR-MEF is distinguished from O-MEF in that SR-MEF allows for short-run structural changes in the electricity system, whilst O-MEF assumes a static system.
- *Build Margin Emissions Factor (B-MEF):* The average CO_2 emissions rate per unit of electricity produced for the next power station expected to be built in an electricity system.
- *Combined Marginal Emissions Factor (C-MEF):* The change in CO_2 emissions relating to a unit change in electricity demand, calculated by weighting the O-MEF and B-MEF to arrive at a "combined" figure.
- *Long-Run Marginal Emissions Factor (LR-MEF):* The change in CO_2 emissions relating to a unit change in electricity demand, where structural change in the electricity system is explicitly taken into account (i.e. demand-side interventions dynamically interact with power stations commissioning and decommissioning, and with system operation).

3. Background

Estimating the change in CO_2 emissions associated with a change in an electricity system has been a topical issue for some years, not least because the choice of methodology used to determine the emissions rate has significant consequences for perceptions of which technology reduces emissions the most (e.g. [9]). As discussed in [8], early attempts to estimate appropriate marginal emissions factors by Voorspools and D'Haeseleer [10,11], Bettle et al. [12] and Marnay et al. [13] used load duration curves combined with assumed, modelled or observed merit orders to ascertain which generators were operating on the margin (i.e. power stations that are likely to respond to system load changes) at any given system load level. The method by which the merit order was constructed in each of these studies varied, with most opting to use historical utilisation data (and assume dispatchable generators with the highest utilisation are first in the merit order) or to model the merit order based on marginal cost of operation (and assume the lowest cost marginal generators are lowest in the dispatch order).

Hawkes [8] adopted a different approach using observed half-hourly dispatch data [14] for large generators in the electricity system in Great Britain (GB). In this study linear regression was applied to the half-hourly change in system emissions versus the corresponding half-hourly change in system demand. This approach enabled fine temporal disaggregation of results (e.g. marginal emissions factor by time of day) and demonstrated that dispatch in the GB electricity system does not strictly adhere to merit order principles. Updated results using this approach for the GB electricity system over the period 2009–2012 is presented in Fig. 1. As shown, the SR-MEF was 0.64 kg CO_2/kWh; a slight decrease since the original assessment in 2010 [8] that considered to 2002–2009 period.

Since this contribution, there have been additional works relevant to the present article: Siler-Evans et al. [15] applied the methodology developed in [8] to assess the US electricity system and extended analysis to further air emissions (SO_2 and NO_x). This study concurred with [8] in that AEFs could significantly misestimate the emissions change associated with a change in the energy system. The basic methodology developed in [8] was also used in Zivin et al. [16] to obtain more spatially-resolved estimate of the MEF in the US grids, and then apply this to assess emissions associated with electric vehicles. Also along these lines Ruiz and Rudkevich [17] develop a spatially-disaggregated model of marginal CO_2 intensities, calculating CO_2 intensity by node in a power network and also investigating the CO_2 implications of relaxation

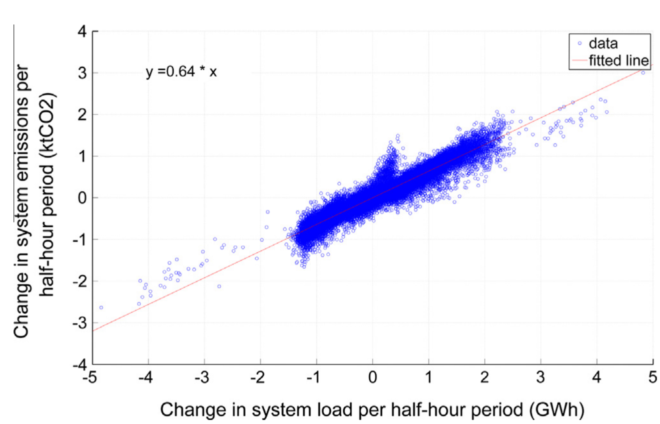

Fig. 1. Short-run MEF observed in the British electricity system for 2009–2012 inclusive. The fitted line represents a least squares linear regression of the data points, forced to pass through the origin, with resulting equation $y = 0.64 * x$.