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Creative accounting: A critical perspective on the market-based method for reporting purchased electricity (scope 2) emissions

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ABSTRACT

Electricity generation accounts for approximately 25% of global greenhouse gas (GHG) emissions, with more than two-thirds of this electricity consumed by commercial or industrial users. To reduce electricity consumption-related emissions effectively at the level of individual firms, it is essential that they are measured accurately and that decision-relevant information is provided to managers, consumers, regulators and investors. However, an emergent GHG accounting method for corporate electricity consumption (the 'market-based' method) fails to meet these criteria and therefore is likely to lead to a misallocation of climate change mitigation efforts. We identify two interrelated problems with the market-based method: 1. purchasing contractual emission factors is very unlikely to increase the amount of renewable electricity generation; and 2. the method fails to provide accurate or relevant information in GHG reports. We also identify reasons why the method has nonetheless been accepted by many stakeholders, and provide recommendations for the revision of international standards for GHG accounting. The case is important given the magnitude of emissions attributable to commercial/industrial electricity consumption, and it also provides broader lessons for other forms of GHG accounting.

1. Introduction

Electricity generation currently produces around 25% of global greenhouse gas (GHG) emissions (Victor et al., 2014), or about 12.4 $GtCO_2e$/year. More than two-thirds of the electricity generated is consumed by commercial and industrial users (IEA, 2016a). To reduce electricity consumption-related emissions effectively at the level of individual firms, it is essential that they are measured accurately and that decision-relevant information is provided to managers, consumers, regulators and investors. The compilation and public reporting of corporate GHG inventories, ostensibly for this purpose, is becoming mainstream business practice (CDP, 2016b). However, an emergent 'market-based' method for quantifying emissions associated with electricity consumption, which allows reporting entities to purchase and claim the GHG attributes associated with renewable generation, is not aligned with reducing emissions or providing accurate or relevant GHG information. This issue is highly topical as recently published reporting guidance from the GHG Protocol (WRI, 2015) has endorsed the market-based approach, while the forthcoming update of ISO 14064-1 for corporate GHG inventories provides an opportunity to establish a more robust approach.

This perspective article aims to inform the development of GHG accounting practice and international standards by providing a synthesis of existing studies, with additional analysis on the implications for GHG accounting. Following a brief introduction to corporate GHG accounting practice and the quantification methods for purchased electricity, we set out two interrelated problems with the market-based method, and then explore why, despite these problems, the market-based approach has been accepted by many stakeholders. We conclude with recommendations for a more robust accounting method, and briefly reflect on the applicability of the lessons learned for GHG accounting more broadly.

2. Corporate GHG accounting and the market-based method

The first internationally recognised guidance for corporate GHG inventory reporting was published by the GHG Protocol in 2001 (WBCSD/WRI, 2004), with a corresponding ISO standard published in 2006 (ISO, 2006a). The GHG Protocol has since published revisions and other standards, including guidance for emissions associated with purchased electricity, termed 'scope 2' emissions (WRI, 2015). 'Scope 2' denotes the point-of-generation emissions from purchased grid electricity (or other forms of purchased energy, such as district heating and cooling), while 'scope 1' covers direct emissions from facilities and

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machinery owned by a reporting company, and 'scope 3' includes any other indirect emissions associated with a reporting company's broader value chain, such as business travel or the disposal of waste (WBCSD/WRI, 2004).

Standard practice is to estimate emissions using activity data for each source and GHG. For example, if a small diesel car is used for business travel, then the CO_2 emissions associated with the car should be calculated using data on its actual fuel consumption or distance travelled, multiplied by a technology-specific emission factor, such as 0.1448 $kgCO_2$/km travelled in a small diesel car (Defra/DECC, 2016). If the specific source is not known then an average emission factor may be used instead, e.g. the emission factor for an average car, 0.1856 $kgCO_2$/km travelled (Defra/DECC, 2016).

One feature of purchased electricity from a public distribution grid, which makes it difficult from an accounting perspective, is that it is not possible to trace the electricity consumed by an entity back to any particular grid-connected power plant (Raadal, 2013). To address this physical reality, it has been standard practice to use a grid average emission factor to estimate scope 2 emissions (e.g. those provided by Defra/DECC (2016) or eGRID (2017)), which is derived by dividing the total emissions from all the generation sources supplying a defined transmission and distribution grid area by the total amount of electricity supplied over a given period (Harmsen and Graus, 2013). This approach is termed the 'locational' or 'grid average' method, as it reflects the average emissions for the *location* in which the consumption occurs (WRI, 2015).

An alternative accounting method is the 'market-based' or 'contractual' approach, which permits a reporting company to apply an emission factor associated with electricity from a specific generation facility, such as a wind farm, with which the reporting company has a contractual agreement to claim the associated emissions attributes. In the case of most renewable technologies, the point-of-generation emissions are zero, and so the reporting company will claim a zero emission factor for its purchased electricity. Contractual arrangements can take place through various instruments, such as Renewable Energy Certificates (RECs), Guarantees of Origin (GOs), utility green tariffs, or power purchase agreements (PPAs). It is worth emphasizing that these contractual arrangements do not entail any changes to how electricity from a renewable facility is physically delivered or consumed. The only thing transacted is a claimed right to use the emission factor associated with a certain amount of generation from a particular renewable energy facility.

The GHG Protocol's *Scope 2 Guidance*, published in 2015, requires that companies use both the locational grid average method and the market-based method to report scope 2 emissions (i.e. dual reporting). However, the guidance also allows companies to choose a single method for meeting their reduction targets and for reporting their supply chain emissions (WRI, 2015). The same guidance has been adopted by CDP, formerly the Carbon Disclosure Project (CDP, 2016a).

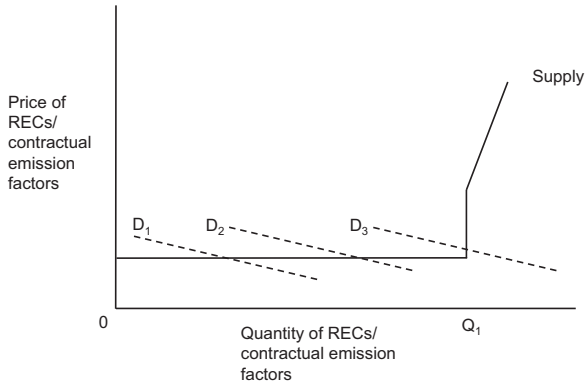

Fig. 1. Demand and supply of contractual emission factors.

In its current form, the guidance does not require the electricity associated with any purchased emission factor to be additional: in other words, it could be from a long-established facility, or one which receives government or other subsidies sufficient to justify its operation already, in the absence of the contractual arrangement.

3. Problems with the market-based method

This section sets out two interrelated problems with contractual emission factors and the market-based accounting method: purchasing contractual emission factors does not influence or affect the amount of renewable electricity generated (except under very specific additionality conditions, which are generally not fulfilled); and the market-based accounting method fails to provide accurate or relevant information in GHG reports.

Problem 1:. *Lack of additional renewable energy generation*

There are structural reasons for expecting that markets for contractual emission factors will fail to influence renewable energy supply. In many countries there are now large amounts of renewable generation available, because of government subsidies, legacy investments or because renewables are already economically viable (IEA, 2016b). The attributes associated with some of this electricity are available for allocation via contractual arrangements, without causing any increase in the amount of renewable electricity generated. In some jurisdictions, e.g. the U.S., renewable attributes used for compliance with regulatory mandates are not also available for sale in the voluntary market, whereas in other jurisdictions, e.g. many EU countries, renewable generation can be used for compliance with regulatory targets and the attributes from the same renewable generation can also be sold in the voluntary market.

This situation, i.e. large amounts of renewable attributes available, is illustrated in Fig. 1, adapted from Gillenwater (2008). Between 0–Q_1 changes in demand for renewable attributes (e.g., shift from D_1 to D_2) only involves the allocation of existing (non-additional) renewable energy output, and the price reflects only the associated transaction costs. A market equilibrium to the right of Q_1 would drive additional renewable generation. However, the higher costs of genuinely additional supply, and the elasticity of demand to higher prices, suggests that the market for contractual emission factors is highly unlikely to cause additional renewable capacity investments.[1] Moreover, in many countries the amount of renewable generation is increasing due to the other drivers, such as government subsidies (IEA, 2016b), and therefore the point at which additionality might be achieved (i.e. beyond Q_1) is continually advancing further beyond the reach of voluntary market demand for contractual emission factors.

As an approximate indication of the demand increase needed before there is an effect on supply, ET Index Research data, which includes 2000 of the world's largest listed companies, shows 97 companies using the market-based accounting method to report lower emissions, equating to 22.2 million tCO_2e/yr.[2] This approximates to ~ 1% of globally available renewable electricity generation in 2015,[3] and therefore demand for contractual emission factors would need to increase a hundred-fold to reach the existing supply threshold for renewable attributes (which is continually increasing anyway), and only once above that threshold would demand cause a fractional increase in

[1] It is possible that there will be an additionality 'window' if the net cost of additional generation does not exceed the market's willingness to pay for renewable attributes, which increasingly may be the case as the cost of new renewable capacity decreases (i.e. the supply curve beyond Q1 will be less inelastic). However, as noted above, this situation would only be expected to arise after the baseline supply threshold has been reached.

[2] Chief Technical Officer, ET Index Research, 2016, personal communication, 24 October.

[3] This indicative estimate is based on 5.530 TWh of renewable electricity generation (derived from U.S. EIA (2016)) and an assumed average grid emission factor of 0.4 tCO_2e/MWh (which approximates to the grid averages for the UK and the US).