Economics of CO_2 Emissions in Power Systems[1]

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Abstract

The paper analyzes the economics of CO_2 emissions in power systems by introducing concepts of marginal carbon intensity (MCI) of electricity demand and shadow carbon intensities (SCI) of binding transmission constraints. It demonstrates that values of MCIs are time and location dependent and exhibit properties similar to those of locational marginal prices of power. These concepts and their properties are discussed using simple examples illustrating their importance and potential use in solving practical problems and designing CO_2 abatement policies.

Introduction

The study of the economics of CO_2 emissions is the study of costs and benefits of CO_2 abatement. Scientists tell us that the emission of greenhouse gases into the atmosphere is a global problem and that when a unit of CO_2 is released into air, the geographic location and, within limitations, the time of this event makes little difference on its consequences. In contrast, as discussed in this article, the time and geographical location of CO_2 abatement actions as well as actions that are not generally considered to be related to CO_2 abatement can make a significant difference in the quantity of emissions as well as the economic efficiency of actions directly or indirectly focused on reduction in CO_2 emissions. This is especially true for the power industry that is characterized by a diverse technological and geographical mix of generation technologies and a constrained transmission network in which avoidance of CO_2 emissions are temporally and spatially dependent in a significant number of ways.

Carbon[3] reduction economic policies are already a reality affecting operations of power systems in many European countries. The U.S. power industry is poised for a

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[3] For the purpose of this paper, terms “carbon,” “carbon dioxide” or “CO_2” are used interchangeably.

national carbon control policy being contemplated by the Federal government and is already subject to certain Regional Greenhouse Gas Initiatives (RGGI), Renewable Portfolio Standards (RPS) and a demand reduction programs at the utility and state levels, all claiming CO_2 reduction as a policy centerpiece. The investment community and industry project developers have expressed an increasing interest in the development of renewable generation technologies such as wind and solar on a massive scale and in construction of high voltage transmission lines to deliver renewable energy to the markets, see for example, CRA (2008), Shavel (2009). These referenced studies provide an example of analyses in which the impact of CO_2 abatement solutions is examined at a highly detailed level of engineering economics involving a combination of security constrained generation dispatch, power flow analysis and emission tracking on a generating unit specific basis. In the process of working on these and other similar studies, the author had to acknowledge the disconnect between the level of detail required by these analyses and a relatively poor system of concepts addressing the economics of CO_2 abatement.

The purpose of this paper is to fill this void and to suggest a "vocabulary and arithmetic" which would help the power industry stakeholders to better understand the economics and operational consequences of CO_2 emissions within the complexity of the interconnected power grid. The detailed engineering and mathematical analysis of CO_2 emissions in constrained power networks presented in this paper is fully developed in Ruiz and Rudkevich (forthcoming). The present paper focuses on the impact of economic decisions on CO_2 emissions and on illustrating the economic implications of time-dependent and locational properties of CO_2 emissions produced by a networked power system that are similar those of locational marginal prices. Understanding these relationships is essential if we are to design and implement policy measures and technological solutions within the power industry that effectively and efficiently address climate change.

Economic Indicators of CO_2 Emissions

Let us consider an electrical grid as a whole and assume that at any moment in time we can measure the total mass of carbon emissions released by all interconnected generators. This is a reasonable assumption, as long as we know the fuel type, heat rate and power output of each generator. Thus, $C(t)$ - total mass of CO_2 emissions produced by the electrical grid measured in tons of CO_2 at time *t*.

Assume now that a market participant finds it economically beneficial to implement a load reduction measure which reduces electricity demand by a small amount at a given location on the grid. An important question is how many units of CO_2 emissions will this measure help to avoid? An indicator providing an answer to this question is *Marginal Carbon Intensity (MCI)* which is equal to the decrease in CO_2 emissions in the electrical network in response to an infinitesimal decrease in electricity demand and measured in (Tons/MWh). As demonstrated below, the *MCI* depends on the time and location of the applied demand reduction measure. The following mathematical formula defining the *MCI* reflects that dependency:

$$MCI_k(t) = \frac{\partial C(t)}{\partial L_k(t)} \tag{1}$$

where $L_k(t)$ denotes demand at time *t* at location *k*. The larger is $MCI_k(t)$ for a given location and time, the greater is the change in the total carbon emission volume response to the change in electricity demand. A positive value of MCI_k implies that at a given location and time an increase/decrease in electricity demand causes increase/decrease in CO_2 emissions in the system. A negative value of MCI_k implies that at a given location and time changes in electricity demand and CO_2 emissions move in opposite directions. (A statistical analysis of demand reduction measures relying on real-time prices reported in Holland and Mansur (2006) indicates that demand reduction could result in an increase in emissions, in this case NOx and SO_2). In order to get a better insight into this indicator, let us consider an unconstrained electrical system dominated by three generating technologies: conventional coal, combined cycle gas-fired (CCg) generation and a simple cycle combustion gas turbine (CTg). Their illustrative characteristics are presented in Table 1.

Table 1. Illustrative Characteristics of Generators

Technology	**Heat Rate (Btu/kWh)**	**Fuel Price ($/MMbtu)**	**VO&M ($/MWh)**	**CO_2 rate (Ton/MWh)**	**CO_2 price ($/Ton)**	**Dispatch cost ($/MWh)**
Coal	9500	2.0	1.0	0.9	10	29
CCg	7000	5.0	3.0	0.4	10	42
CTg	11000	5.0	5.0	0.6	10	66

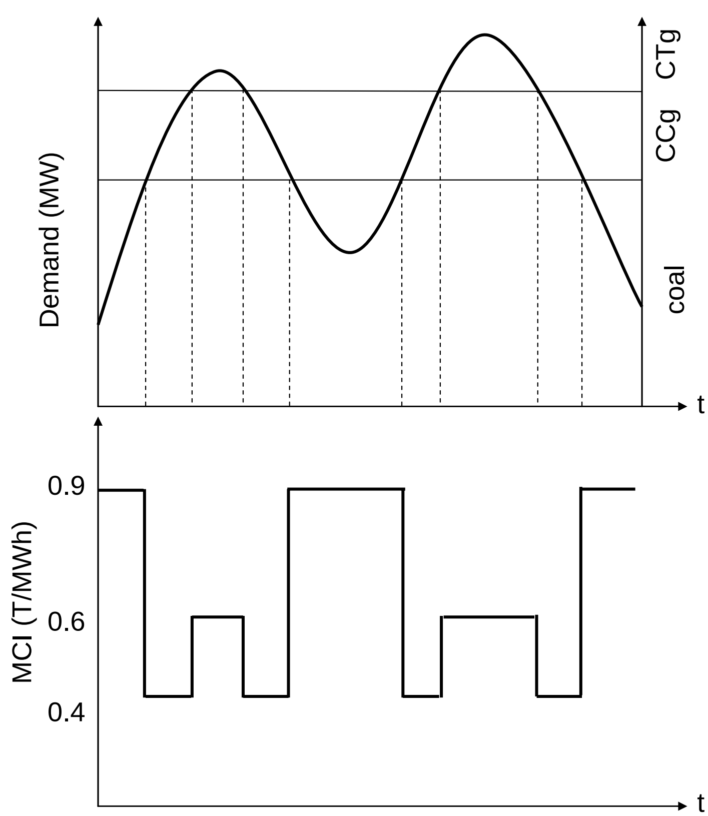
Parameters presented in this table are typical for these generating technologies. For the purpose of this example, we assume a $10/Ton value of CO_2 emissions reflecting a CO_2 control policy in a form of a carbon tax or a price associated with a cap-and-trade program. For generators, this value represents an expenditure which they factor into their dispatch cost along with fuel and variable O&M expenses. The dispatch cost determines a merit order in which generators are deployed while serving system demand. The most expensive generator needed to meet the demand in a given hour is known as the marginal generator. All generators below the marginal generator in the merit order are dispatched at their full capacity, while generators above the marginal generator are not dispatched at all. The marginal cost of electricity is set by the cost of the marginal generator.[4]

A small enough increase or decrease in electricity demand in a given and short enough time period causes an equal (in absence of losses) increase or decrease in output

[4] In this and all other examples we assume that generators are always deployed on the basis of their dispatch costs.

of the marginal generator. Therefore, in each time period the marginal carbon intensity is determined by the emission rate of the generator that is marginal during that period. This is illustrated graphically on Figure 1 which depicts a chronological demand profile for a day, marginal generation technology at each point in time and the resulting dynamics of the MCI. As this figure demonstrates, marginal carbon intensity can vary significantly over time by following the change of the marginal generator. An answer to the originally posed question, the amount of carbon avoided by a small load reduction will be changing over time and and will depend on the marginal generator operating at any point in time. Temporal changes in the amount of avoided carbon are significant and could vary by a factor of greater than two when the marginal generating technology switches between convential coal and combined cycle gas-fired generation.

Figure 1. Electricity Demand, Marginal Generators and Marginal Carbon Intensity over Time



It is important to note that at any point in time in this example the CO_2 price per ton of carbon emissions P_C remains constant ($10/Ton). However, when measured on a per MWh basis, this price changes following the change in the MCI. In nodal electricity markets with the price structure based on the concept of the locational marginal price (LMP), this consideration provides for the following general formula for the *CO_2 component of the locational marginal price* (*CLMP*) of electricity:

$$CLMP_k(t) = MCI_k(t) \times P_C(t) \tag{2}$$

which effectively expresses the locational value of CO_2 emissions measured on a per MWh basis. This formula is even more general than what we considered in the above example, because it allows for the price of carbon to vary with time. The economic meaning of the the CO_2 component of LMP is the location-and-time specific value placed by the power system on avoiding CO_2 emissions through an infinitesimal reduction of electricity demand. A CO_2 component of LMP is what the buyer of electricity effectively pays for carbon on a per MWh basis.

Consider now the difference between MCI at a generator's location and a CO_2 emission rate $\sigma_k(t)$ of that generator which is equal to

$$CD_k(t) = MCI_k(t) - \sigma_k(t) \tag{3}$$

which could be characterized as a *CO_2 differential* of the generator. The CO_2 differential is equal to the marginal saving in system-wide CO_2 emissions provided by the generator. Increasing generator's output by a small amount would displace output of the marginal generator by the same amount. As a result, the marginal change in system emissions will be exactly equal to the generator's CO_2 differential, as shown by formula (3).

A positive CO_2 differential indicates that if it were possible to increase generator's output above optimally determined level, it would reduce system-wide emissions. A negative CO_2 differential indicates that in order to decrease system-wide emissions the generator has to be ramped down below the optimally determined level while the marginal generator will be ramped up.

In the above example, coal-fired generation will have a negative CO_2 differential whenever the marginal generator is gas-fired and a zero CO_2 differential when it is marginal. Combined cycle generation will have a positive CO_2 differential whenever other generating technologies are marginal and zero when it is marginal. Simple cycle generation will see a positive CO_2 differential with coal on the margin and negative one with combined cycle on the margin.

Multiplying a CO_2 differential by the underlying price of carbon will result in the *CO_2 margin* of a generating unit

$$CM_k(t) = P_C(t) \times \left[MCI_k(t) - \sigma_k(t) \right] = CLPM_k(t) - P_C(t)\sigma_k(t) \tag{4}$$

which is the difference between the locational CO_2 component of LMP and generator's costs of carbon emissions per unit of output. A generator's CO_2 margin equals the marginal saving in total carbon costs incurred by the power system from an increase in the generator's output. A positive CO_2 margin implies that the market value of avoiding CO_2 emissions is higher than the carbon costs incurred by the generator and therefore the market will reward the generator with a premium if it runs. A negative CO_2 margin implies that the market value of avoiding CO_2 emissions is lower than the carbon costs incurred by the generator and therefore the market will penalize the generator should it run.

From the perspective of carbon reduction it is preferable not to dispatch generators with negative CO2 margins. This, however, is only possible at high enough CO2 prices when generator's merit order is aligned with generators' carbon emission rates. At CO2 prices that do not align the merit order with carbon emissions, marginal carbon intensities will exhibit a non-monotonic relationship with respect to electricity demand, as shown on Figure 1 and certain generators with negative CO_2 differentials will be dispatched. In other words, cost minimization in the power system would not be aligned with minimization of CO_2 emissions.

The above discussion of the marginal carbon intensity in an unconstrained lossless system could be summarized by the following formula

$$MCI_k(t) = \sigma_*(t) \tag{5}$$

i.e. marginal carbon intensity at all locations is equal to the carbon emission rate of the marginal generator $\sigma_*(t)$.

Accounting for marginal losses in a transmission grid will lead to locational MCIs even in the absence of transmission constraints. Indeed, transmission losses incurred to serve incremental loads at different locations will be different. The same decrease in demand at different locations will require different reductions in generation by the marginal unit. Accounting for losses leads to the following the formula for MCI:

$$MCI_k = \sigma_*(t)(1 + \mu_k(t) - \mu_*(t)) \tag{6}$$

where μ_k and μ_* are marginal loss factors for the location k and marginal unit, respectively. The difference in loss factors reflects marginal losses required to deliver power from the marginal generation to the location in question.

In a power network, when some transmission constraints bind, there are multiple marginal generating units[5] each with a different emission rate. A demand decrease at a given location requires a redispatch of these marginal units, some of which may have to be ramped down, some ramped up and other should remain unmoved in order to respond to a decremental demand without violating the security of the transmission system. In

[5] Typically the number of marginal units equals the number of binding transmission constraints plus 1.

sum, marginal units have to be moved in tandem, in proportion to each other resulting in the following formula for locational MCI.

$$MCI_k = \sum_{j=1}^{m} \alpha_{kj} \sigma_j \tag{7}$$

where m is the number of marginal units, $\sigma_1,...,\sigma_m$ are CO_2 emission rates of marginal units, α_{kj} are location-specific proportionality coefficients such that $\sum_{j=1}^{m} \alpha_{kj} = 1$. A detailed derivation of this formula is provided in Ruiz and Rudkevich (forthcoming).

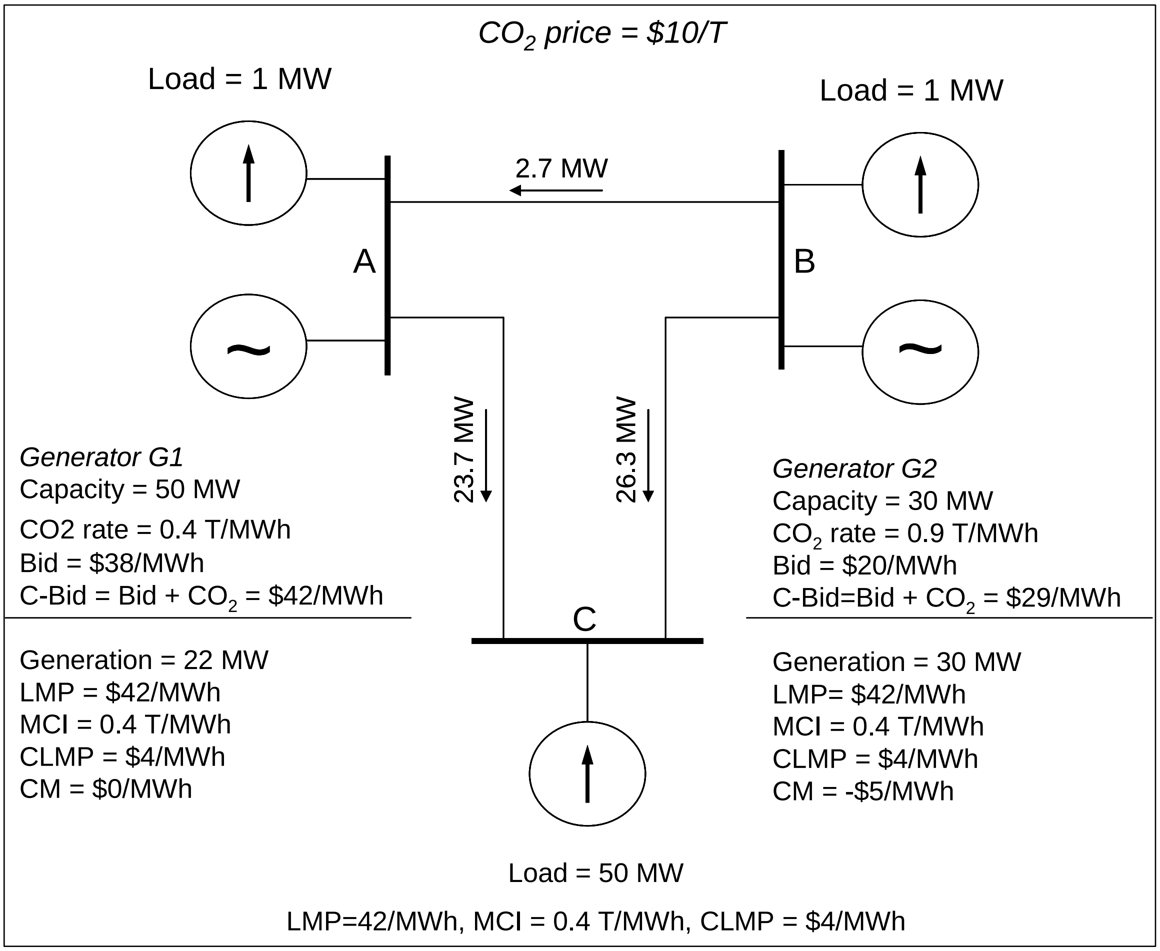
In order to illustrate the locational properties of marginal carbon intensity of the electrical grid, let us consider several examples of the optimal environmental dispatch using a simple case of a three-bus power grid. These examples are discussed in the next section.

Marginal Carbon Intensity on a Three-bus Network

Consider a three-bus electrical network depicted on Figure 2 which includes two generators G1 and G2 located at buses A and B, respectively and three loads, one attached to each bus. Loads at buses A and B are relatively small, 1 MW each. Bus C has the largest load, 50 MW and no generation attached to it. Each generator is characterized by capacity (MW), bid prices ($/MWh) and CO_2 emission rate (Ton/MWh). For the purpose of this example, we consider two bid price parameters. Parameter labeled "Bid price" reflects generator's fuel costs and non-fuel variable O&M expenses. "C-Bid price" includes also the cost of CO_2 emissions computed as a product of the generator's emission rate and the price of carbon, $10/Ton in this example. The optimal dispatch of this system should be performed on the basis of C-Bids thus internalizing the cost of carbon. Parameters of generators G1 and G2 correspond to parameters of the combined cycle gas fired and conventional coal generators presented in Table 1.

In absence of transmission constraints in this system and assuming no transmission losses, the optimal dispatch is obvious: we should utilize the least expensive resource (generator G2) up to its capacity of 30 MW and meet the remaining 22 MW of demand from generator G1.

Figure 2. A Three-bus Network, Unconstrained Case



Generator G1 located at bus A is marginal and in absence of transmission constraints it sets the price for the entire system, i.e. LMPs at all three buses are the same and equal the C-Bid of generator G1, i.e. $42/MWh.

Assuming that all three lines A – B, A – C and B – C have the same impedance, 1/3 of power injected at bus A flows to load at bus C along the long path A – B – C and 2/3 flows along the short path A – C. The same rule holds for power injected at B, 1/3 flows over the long path B – A – C and 2/3 over the short path B – C. Resulting flows are shown on Figure 2.

In an unconstrained example presented on Figure 2, a single marginal unit (G1) sets the price and at the same time defines the MCI for all locations, 0.4 Ton/MWh. The carbon component of the LMP is therefore $4/MWh. In this example, reducing demand by 1 MWh at any location would reduce carbon emission by 0.4 Ton, would save $42 in total generation costs of which $4 would be on account of carbon reduction. Generator G1 has CO_2 margin of zero, while generator G2 has negative CO_2 margin of -$5/MWh.

Table 2. Carbon Cost Outlay, Unconstrained Example, $10/Ton Carbon

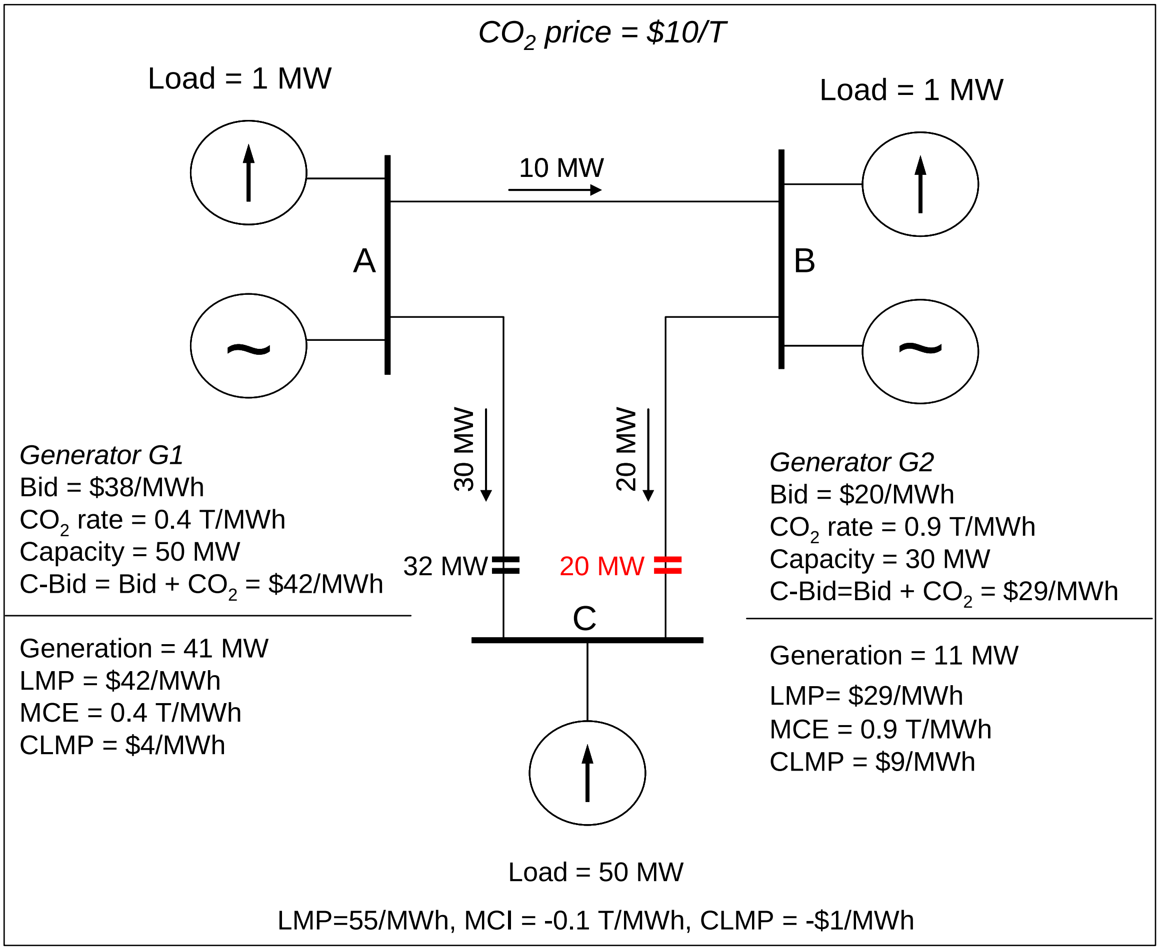
Bus	CLPM ($/MWh)	Load Payments	Generator receipts	Generator Costs	Generator Margins
A	$4	$4	$88	$88	$0
B	$4	$4	$120	$270	-$150
C	$4	$200	$0	$0	$0
Total		**$208**	**$208**	**$358**	**-$150**

Table 2 presents an outlay of carbon costs in an unconstrained case. As shown in that table, total costs of CO_2 emissions to generators amount to $358. However, loads only pay $208 in LMPs which are fully transferred to generators. Generator G1 is CO_2 neutral (its CO_2 margin is zero) while generator G2 has a negative CO_2 margin and is responsible for the $150 in difference between its CO_2 related costs and revenues received from loads.

A more interesting example is presented on Figure 3 depicting the case of a constrained network. In this example we assume that the flow on the line B – C is limited at 20 MW and the flow on the line A – C is limited by 32 MW. A dispatch presented on Figure 2 is not feasible, because it results in a B – C flow of 26.3 MW which is above the limit. A redispatch is necessary in order to accommodate this constraint. Optimal dispatch and corresponding LMPs are shown on Figure 3 with line B – C now operating at its maximum rating of 20 MW while line A – C remains unconstrained. In this case, both generating units G1 and G2 are marginal. LMPs at their buses are equal to their C-Bids of $42/MWh and $29/MWh, respectively. LMP at bus C is equal to $55/MWh. Following the LMP derivation for each bus is important, as the same process helps to derive locational values of MCI.

Assuming a 1 MW reduction of demand at bus A allows us to reduce generation at that bus without distorting flows in the rest of the system and saves $42, hence LMP at A is $42/MWh, a cost of G1. Reducing demand at bus B only allows us to reduce generation at G2 without distorting system flows and violating binding constraint B – C. Thus, reducing demand at B by 1 MW yields the saving which is equal to the cost of G2, $29, hence the LMP at B is $29/MWh. Reducing demand at bus C by 1 MW requires a redispatch of generators in order not to violate the transmission constraint B – C. Generator G1 has to be reduced by 2 MW while generator G2 ramped up by 1 MW. Hence the avoided cost of demand reduction and LMP at C is $55/MWh = 2 x $42/MWh – 1 x $29/MWh.

Figure 3. Three-bus Network, Constrained Case, \$10/Ton CO_2



The same logic is applicable to computing locational marginal carbon emission intensities. A load reduction at bus A reduces an output of unit G1; MCI at this bus equals 0.4 Ton/MWh, an emission rate of G1. A load reduction at bus B reduces an output of unit G2 and MCI at B is equal to that generator's emission rate of 0.9 Ton/MWh. As explained earlier, a 1 MW load reduction at bus C will cause a decrease of generation at bus A by 2 MW and an increase of generation at bus B by 1 MW. The result of this redispatch is a decrease in carbon emissions at bus A by 2 x 0.4 Ton/MWh and an increase of carbon emissions at bus B by 0.9 Ton/MWh adding up to an overall 0.1 Ton/MWh increase in carbon emissions. Thus, the MCI at bus C = - 0.1 Ton/MWh.

Given these results we can conclude that demand reduction at buses A and B causes a reduction in carbon emissions but demand reduction at bus C actually increases carbon emissions despite the fact that this location has the highest demand and highest prices in the system and therefore is the most attractive target for a demand response program. Although a demand response program implemented at this location may make the most economic sense, it would not reduce carbon emissions but instead increase them.

With the same example in mind, consider now the possibility of adding 1 MW of carbon-free wind generation to this system. Assuming zero operating costs of wind power, the mathematical impact of this generation addition would be the same as a 1 MW reduction in demand. Wind addition to buses A or B would reduce carbon emissions by 0.4 Ton or 0.9 Ton, respectively. However, an addition of 1 MW of carbon free wind generation at bus C would increase system-wide carbon emissions by 0.1 Ton.

Table 3. Carbon Cost Outlay, Constrained Example, \$10/Ton Carbon

Bus	**CLPM (\$/MWh)**	**Load Payments**	**Generator receipts**	**Generator Costs**	**Generator Margins**
A	\$4	\$4	\$164	\$168	\$0
B	\$9	\$9	\$99	\$99	\$0
C	-\$1	-\$50	\$0	\$0	\$0
Total		**-\$37**	**\$263**	**\$263**	**\$0**

Table 3 provides an outlay of carbon costs in the constrained case presented on Figure 3. As shown in that table, total costs of CO_2 emissions to generators amount to \$263 which is less than in the unconstrained case, due to a reduced output of the constrained generator with high carbon emission rate at bus B. In this constrained case, since both generators are marginal, their CO_2 costs match their CO_2 receipts. In sum, generators are fully compensated for their CO_2 costs whereas loads appear to be paid for carbon rather than paying for it. As explained in the next section of this paper, this seeming discrepancy is attributed to the CO_2 induced decrease in congestion rent.

It is important to note, however, that the above results are not absolute and depend on the underlying price of CO_2 emissions. To illustrate that, consider yet another example presented on Figure 4. The key difference between this example and the one presented on Figure 3 is the underlying price of carbon. Instead of $10/Ton used earlier, we now consider a $40/Ton price of CO_2 emissions. This higher carbon emission price changes the merit order of generators G1 and G2. As a result, the dispatch changes such that line B – C is no longer constrained, but congestion moves to line A – C which now operates at its maximum rating of 32 MW. Both generators are again marginal with prices at buses B and C being equal $54/MWh and $56/MWh, respectively. LMP at bus C is now equal to $58/MWh since now a redispatch needed to accommodate a 1 MW demand reduction at bus C requires a 2 MW decrease of generator G2 and 1 MW increase of generator G1. Marginal carbon intensities at buses B and C remain the same as in the previous example, but marginal carbon intensity at bus C now equals +1.4 Ton/MWh. Indeed, a 1 MW reduction in demand at C will result in a 2 MW decrease of output of G2 and 1 MW increase of G1. Hence, MCI at C equals 2 x 0.9 Ton/MWh – 1 x 0.4 Ton/MWh = 1.4 Ton/MWh.

Figure 4. Three-bus Network, Constrained Case, \$40/Ton CO_2

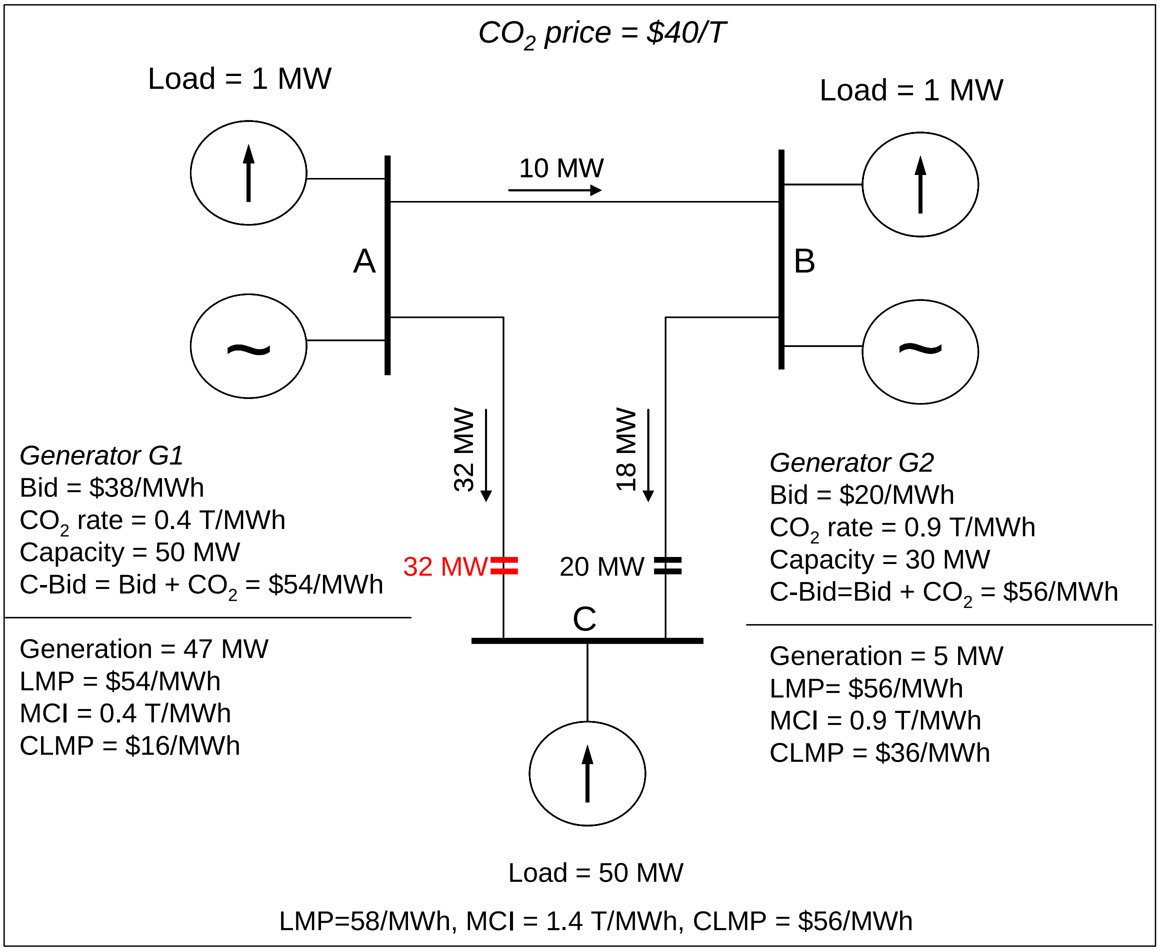


Table 4 provides an outlay of carbon costs in the constrained case presented on Figure 4. As shown in that table, total costs of CO_2 emissions to generators amount to \$932. In this constrained case, as in the previous one, both generators are marginal and their CO_2 costs match their CO_2 receipts. In sum, generators are fully compensated by their CO_2 costs. However, in this case load payments for CO_2 emissions exceed generators receipts by \$1920. As explained in the next section of this paper, this discrepancy is attributed to the CO_2 induced increase in congestion rent.

Table 4. Carbon Cost Outlay, Constrained Example, $40/Ton Carbon

Bus	CLPM ($/MWh)	Load Payments	Generator receipts	Generator Costs	Generator Margins
A	$16	$16	$752	$752	$0
B	$36	$36	$180	$180	$0
C	$56	$2800	$0	$0	$0
Total		**$2852**	**$932**	**$932**	**$0**

Comparison of the last two examples shows that an increase in the price of carbon could make a significant change in transmission congestion. With shifting of congestion from B – C to A – C, the carbon intensity of bus C changes in both the sign and magnitude. Note also that while the LMP at bus C changed by a mere $3/MWh between the two scenarios, the CO_2 component of LMP changed by $43/MWh going from negative -$1/MWh to $42/MWh. The same reversal in results would also apply to the consideration of renewable generation. Under a high CO_2 price scenario, adding renewable resources to bus C will be a highly effective CO_2 reduction measure.

Interplay between Transmission Congestion and CO_2 Emissions

An impact of transmission congestion on the locational effectiveness of CO_2 reduction measures calls for a more thorough analysis of this phenomenon. In order to address this issue on a systematic level, let us introduce a notion of shadow carbon intensity of a transmission constraint. Similarly to the definition of the economic shadow price, let us define a shadow carbon intensity of a transmission constraint *SCI* as a reduction in CO_2 emissions in the entire system in response to an infinitesimal increase in the rating of that transmission constraint and measured in Ton/MW. In other words,

$$SCI_r = -\frac{\partial C}{\partial F_r} \quad (8)$$

where SCI_r is a shadow carbon intensity of transmission constraint *r* and F_r is the rating of that constraint. Transmission constraints which do not bind have zero SCI – increasing line ratings for these constraints would make no impact on overall carbon emissions. Relieving a constraint with a positive SCI value will result in a reduction of carbon emissions, while relaxing a constraint with a negative SCI value will increase overall carbon emission in the system. Another significance of this concept is that locational marginal carbon intensities and shadow carbon intensities of transmission constraints are linked by the same fundamental equation as LMPs and shadow prices of binding transmission constraints:

$$MCI_k = MCI_0 - \sum_{r=1}^{R} \Psi_{kr} \times SCI_r \quad (9)$$

where MCI_0 is the MCI at the reference bus, *R*- number of transmission constraints and Ψ_{kr} - are shift factor coefficients. The derivation of this formula and the computational methodology required to calculate MCIs and SCIs for power networks is developed in Ruiz and Rudkevich (forthcoming).

Let us compute shadow carbon intensities of binding transmission constraints in the above three-bus examples. In the Figure 3 example with \$10/Ton carbon price, the constrained element is line B – C. Increasing the rating of this constraint by 1 MW would allow us to increase a dispatch of unit G2 by 3 MW while reducing by 3 MW dispatch of unit G1. Doing so will reduce dispatch costs by – \$39 = 3 x \$29 – 3 x \$42, but will increase carbon emissions by 1.5 Ton = 3 x 0.9 Ton – 3 x 0.4 Ton. In other words, the shadow carbon intensity of constraint B – C is negative 1.5 Ton. That explains why any attempt to relieve this constraint by reducing demand or adding renewable generator to bus C results in an increase of CO_2 emissions.

In the Figure 4 example with a \$40/Ton carbon price, constraint A – C is binding. Increasing the rating of this constraint by 1 MW would allow us to increase a dispatch of unit G1 by 3 MW while reducing by 3 MW dispatch of unit G2. Doing so will reduce dispatch costs by – \$6 = 3 x \$54 – 3 x \$56 and will reduce carbon emissions by 1.5 Ton = 3 x 0.9 Ton – 3 x 0.4 Ton. In other words, the shadow carbon intensity of constraint A – C is positive 1.5 Ton/MWh. That explains why in this example a relief of this constraint by demand reduction or addition of renewable generation to bus C results in a decrease in CO_2 emissions.

As shown in Ruiz and Rudkevich (forthcoming), the following relationship holds

$$\sum_{k=1}^{N} CLMP_k \times \left[L_k - G_k \right] = P_c \sum_{r=1}^{R} SCI_r \times F_r \tag{10}$$

where N is a number of buses in the electrical network, L_k and G_k are load and generation, respectively, at each bus, P_c is the carbon price, SCI_r and F_r are a shadow carbon intensities and ratings of transmission constraints in the system. The value in the left hand side is the difference between load payments and generator receipts for CO_2 emissions which could be characterized as CO_2 contribution to congestion rent, or *CO_2 congestion rent*.

In systems with a positive CO_2 congestion rent, as in the example presented on Figure 4, loads pay for CO_2 in LMPs in excess of generator receipts. This is indicative of the fact that relieving transmission congestion in the system would be beneficial to the reduction in CO_2 emissions and would thereby reduce load payments for carbon. It is easy to verify that in this example CO_2 congestion rent satisfies equation (10) and is equal to \$1920.

In systems with a negative CO_2 congestion rent, as in the example presented on Figure 3, LMP-based load payments for CO_2 are lower than generator receipts. This is indicative of the fact that relieving transmission congestion in the system would not be beneficial to the reduction in CO_2 emissions and would increase load payments for carbon. Again, it is easy to verify that in this example, CO_2 congestion rent satisfies equation (10) and is equal to -$300.

Analysis of shadow carbon intensity of transmission constraints and of CO_2 congestion rent may serve as an efficient screening tool helping to identify the impact of individual transmission constraints on CO_2 emissions in the system and find congestion relief targets which will be aligned with the objective of reducing carbon emissions.

Implications for Investors, Market Participants and Policymakers

Acknowledging the temporal and locational nature of CO_2 economics of the power industry has numerous implications for a wide range of industry stakeholders. There are a number of public policy and individual economic decisions that are directly affected by the discussion of the temporal and locational nature of CO_2. The discussion below covers four specific areas that are not intended to be exhaustive but rather illustrative. These are: (1) implications for demand reduction; (2) the impact on Renewable Portfolio Standards; (3) the effect on transmission constraints and transmission planning; and (4) the effect on electricity market design.

Implications for Demand Reduction

The effect of energy conservation on CO_2 emissions reduction critically depends on the location of demand reduction measures on the grid, time of use and on the underlying price of carbon. As examples above demonstrate, energy conservation does not necessarily cause a reduction in CO_2 emissions. Reducing demand in off-peak hours of low prices may avoid more CO_2 emissions than reducing demand during peak hours of high prices. Moreover, by the same measure, the amount of avoided carbon at any location will depend significantly upon the underlying price of carbon. These factors need to be taken into consideration by electricity consumers making a decision to install energy conservation technologies, especially if the decision is not made purely on an economic basis, i.e., if an additional objective is CO_2 reduction. Given the growing awareness of electricity consumers of their carbon footprint, it is critically important for the industry to provide consumers with the location-specific and time-of-use sensitive information of the impact of electricity consumption on carbon emissions and on the potential efficiency of conservation measures in reducing that footprint. Equally important is a provision of this information to policymakers responsible for the design and approval of energy conservation programs targeting a reduction in CO_2 emissions. Using locational information will help to significantly improve design of these programs by giving designers means to better foresee the results and by giving program participants better price and quantity signals. For example, if the program envisions the same subsidy for installing certain demand reducing equipment, regardless of the location of that installation on the gird, the results in terms of carbon reduction will vary by location while the subsidy received by program participants would not. If, however, the subsidy were made dependant on expected, measurable reduction of CO_2 emissions, the efficiency of the program with respect to this target could be significantly improved.

Implications for Renewable Portfolio Standards

Another area where locational details of the CO_2 economics are essential is the design and implementation of Renewable Portfolio Standards (RPS). Their objectives and participation criteria vary significantly by state and while reduction of CO_2 emissions is not the only goal of these programs, as a rule, it is among the critical ones. RPS targets are typically defined in terms of annual generation quantity or a per cent of regional demand obtained from renewable sources. Incentives provided to developers of renewable resources are tied to total renewable energy produced. As the above discussion demonstrates, the impact of RPS on the reduction of CO_2 emissions can vary dramatically by location and will depend on the underlying price of carbon. Providing policymakers in charge of RPS design and approval and developers of renewable generation with information in the form of locational marginal carbon intensity and designing renewable energy credits (RECs) to incorporate this information would improve the efficiency of RPS in reducing carbon emissions. Indeed, renewable generation produced at different locations on the grid causes different carbon reduction. If, however, the number of RECs received by each resource were made proportional to marginal carbon intensity at the resource location, compensation provided by RECs will be aligned with the objective of CO_2 reductions.

Implications for Transmission Development

Tapping renewable sources of energy such as wind and solar generation will require major developments of new transmission lines and major upgrades to transfer capability of transmission within known corridors. As the above discussion demonstrates, relieving existing congestion does not necessarily imply carbon reduction. Relieving constraints with negative shadow carbon intensity may cause an increase in CO_2 emissions by dispatching presently constrained out generation sources with negative carbon differentials at a higher capacity factor. Moreover, congestion patterns themselves depend on the underlying price of carbon. Development of transmission projects require regulatory approvals at the state and federal level and are subject to significant public scrutiny involving various stakeholders representing different interests and targeting different goals. Understanding of the impact of the project on CO_2 emissions will be an essential element of the cost-benefit assessment within the stakeholders' consideration. Reporting of key indicators of CO_2 economics, their forecasting and analysis should be part of the tool kit used in such cost-benefit studies.

Implications for Electricity Market Design

Internalizing the economics of CO_2 into the operations of electricity markets is not difficult. As long as each generator knows its CO_2 emission rate and an underlying cost of carbon (either in the form of the carbon tax or the price of emission allowances under the cap-and-trade program), the generator will factor this information into its variable operating costs. These costs will then be factored into an optimal dispatch procedure according to particular rules of the market in which the generator operates.

In centralized markets administered by the Independent System Operator (ISO) the generator will translate these costs into price offers submitted to the ISO. The ISO in turn will process the bid offers through the day ahead and/or real-time market engine, determine the optimal unit commitment and/or dispatch, identify binding transmission constraints and their shadow prices, compute marginal losses, Locational Marginal Prices (LMPs) and their respective congestion and marginal loss components. In order to provide market participants and industry stakeholders with explicit information on locational carbon intensity and shadow carbon intensity of binding transmission constraints, ISOs should have access to explicit and verifiable data on CO_2 emission rates of all generation units. Calculation of MCIs, CO_2 components of LMPs and shadow carbon intensities of binding transmission constraints will not require significant modifications to the operation of the ISO market engine. As shown in Ruiz and Rudkevich (forthcoming), required calculations are not computationally intensive and could be performed without difficulty along with the computation of LMPs and shadow prices of binding transmission constraints. In sum, centralized markets with LMP-based congestion management should have little difficulty with publishing day-ahead and/or real-time indicators of CO_2 economics side by side with basic LMP and congestion information ISOs publish on a regular basis.

In non-nodal markets and in traditional vertically integrated utilities developing and reporting day-ahead and/or real-time indicators of CO_2 economics is theoretically possible but it will depend on actual rules and operational procedures used in these markets. To the extent that the dispatch and operational procedures explicitly identify marginal generators and binding transmission constraints, it should not be difficult to compute locational MCIs and shadow carbon intensities of binding constraints.

In making forward looking decisions, policymakers and industry stakeholders will need forward looking location-specific information on carbon intensities. This information may be derived from the use of simulation models which could be applied to organized LMP-based electricity markets as well as to non-nodal markets and to traditional vertically integrated utilities. In cases when the performance of already implemented measures such as RPS or demand reduction options should be measured against the actual market operation, calculation of day-ahead or real-time MCIs will be needed. In this case, LMP-base markets would be better equipped to provide such indicators than non-nodal markets or traditional utility systems.

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