

# Carbon taxation and feed-in tariffs: evaluating the effect of network and market properties on policy effectiveness

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**Abstract** This paper evaluates how the effect of introducing a carbon emission tax and/or feed-in tariffs on capacity expansion decisions of generating companies varies depending on the number and size of competing firms and technical conditions of the network. To do so, it uses a Nash–Cournot model of the electricity market. This model is then applied to the IEEE 6-bus network. We study three cases: one with only a carbon tax consistent with current carbon prices; one with only a feed-in tariff consistent with current US levels, and one with simultaneous carbon taxation and feed-in tariff. We show that, at least in our case, the quantity of renewable capacity expansion and the electricity prices depend more significantly on the technical conditions of the network and the number of competitors in the market than it depends on the presence of economic penalties or incentives. We also show how interactions between imperfectly competitive markets and physical networks can produce counterintuitive results, such as an increase in consumer prices as a result of a reduction in network congestion. Our results imply that no two countries would experience the same effects from a policy on carbon tax and feed-in tariff if their electricity market does not have similarities in technical and competitive conditions.

**Keywords** Electricity market · Competition · Capacity expansion · Carbon taxation · Feed-in tariff

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## 1 Introduction

Over the last decades, the structure of many electricity markets has evolved from a regulated monopoly to a deregulated, competitive market. Usually, market deregulation leads to an increase in competition. However, in many markets, the number of firms involved in electricity generation remains small despite electricity market deregulation. For this reason, competition among electricity generating firms is usually oligopolistic in nature. Moreover, because electricity is a homogeneous product which is not distinguishable according to the fuel source used for its generation; without some secondary trading mechanism, there is the tendency for generating companies (gencos) to use the cheapest fuel to maximize profits. This choice often has negative environmental effects (such as carbon emissions) which are often not properly priced or considered by the gencos. For instance, in 2012, electricity generation accounted for 12.4 Gigatonnes of CO<sub>2</sub> globally [6], making it the largest single contributor to CO<sub>2</sub> emissions.

Efforts are being made by different countries to realise a low carbon electricity sector; central to many of these efforts are policies on carbon taxation and/or the introduction of renewable subsidies. As a result, investment decisions by electricity generating firms have changed to incorporate environmental performance [2]. However, in an oligopolistic setting, renewable policies may change the nature of competition and the ability of firms to exert market power.

Various studies have assessed the effect of carbon policies, particularly the European Union Emission Trading Scheme (EU-ETS) on the electricity market. Some of the markets studied are those in Finland [8], Spain [10], United Kingdom [7], Nordic area [16], the Netherlands–French–German–Belgium markets in [1] and the entire EU region in [11]. These studies all agree that when EU-ETS was first introduced, it caused an increase in both the generators' profits and electricity prices, showing that there are likely to be some market power effects.

Most market models that have been used to analyse the effects of carbon policies such as [5] do not have an adequate representation of the oligopolistic nature of the electricity sector. While these complications were considered in [14, 15], the models presented could not handle the technicalities of the sector. Aside this, these models do not consider renewable subsidies, an alternative to carbon taxation.

Other models [3, 21] do incorporate both carbon trading and Green Certificates, similar to the current paper. However, again, the inability of these models to adequately characterize imperfect competition in electricity sector is their biggest drawback. [9] recognizes both the oligopolistic structure of the electricity sector and its technical characteristics and incorporates these into a model, but does not examine how generation capacity expansion would depend on the number of generating companies involved in electricity market, which is an important variable.

In this paper we therefore bring together the above approaches to investigate how the effect of introduction of carbon emission tax and feed-in tariffs on capacity expansion decisions of generating companies varies depending on the number and size of competing firms and technical conditions of the network. To do this, a Nash–Cournot based mathematical model of an electricity market is constructed, taking into consideration the technical characteristics of electricity networks. The Nash–Cournot model

of an electricity market has been used extensively in analysing the power market and the impacts of technical characteristics of the transmission network [22] and allows for simultaneous consideration of the technical characteristics of the network, which other, more complex market representation (such as Supply Function Equilibria) would make difficult.

Since the size of electricity markets differ from one country to another and the number of participating companies differ, the behaviour of the market participants would also differ. This work addresses these issues; the model used to address them and its comprehensive mathematical explanation is presented in subsequent sections.

The remaining sections are outlined as follows: Sect. 2 discusses in detail how our Nash–Cournot model was constructed. The network structure, input data and cases considered are presented in Sect. 3. Results obtained when our model was applied to the electricity network of Sect. 3 is analysed in Sect. 4. The conclusions and policy implications are discussed in Sect. 5.

## 2 Methodology

The model built for this research is an extension of the model used in [4]. Minimum generation levels, carbon emission taxes and renewable subsidies have been added to Hobbs' model. As the original model does, we will assume a static model in which generating firms simultaneously decide on capacity expansion and generation levels, in an open-loop fashion, while transmission is operated using a congestion pricing scheme, such that the Nash–Cournot market equilibrium can be found by solving a mixed complementarity problem (MCP).

### 2.1 Model parameters and variables

Throughout, indices are used to denote key elements:  $k, m$  indicates the bus/node,  $z$  indicates the generating facility,  $l$  is used to refer to the transmission lines while  $\alpha$  indicates the genco. Model Parameters are uniquely represented, for instance,  $IC_{akz}$  refers to the cost to build generator  $z$  located at bus  $k$  and belonging to genco  $\alpha$ ; the various model parameters and variables are listed in Table 1 below.

### 2.2 Model characteristics

To preserve linearity, at each bus in the network a linear demand function is assumed:

$$P_k(Q_k) = P_{0k} - \left( \frac{P_{0k}}{Q_{0k}} \right) Q_k. \quad (2.1)$$

Generators compete to satisfy this demand, simultaneously choosing generation levels and expansion to maximize their profits, subject to constraints.

Carbon emission tax and renewable subsidy (Feed-in Tariffs) are incorporated into this model. These are two of the major approaches used by various countries in the

**Table 1** List of parameters and variables

Parameters	
$P_{0k}$	Price intercept
$Q_{0k}$	Quantity Intercept
$C_{akz}$	Marginal generating cost
$PC_{akz}$	Price of carbon in \$/tonne
$E_{akz}$	Carbon emission in tonne/MWh
$IC_{akz}$	Investment cost to build a new generator
$RI_{akz}$	Feed-in tariff
$G_{max_{akz}}$	Maximum generating capacity
$G_{min_{akz}}$	Minimum generating capacity
$F_{min_1}$	Maximum power flow from the lines
$F_{max_1}$	Maximum power flow to the lines
$PTDF_1$	Power transmission distribution factor
Variables	
$x_{pakz}$	Capacity expansion by each generating unit
$p_{wakz}$	Power generated by generator
$q_{ak}$	Sales by each genco at each bus
$q_k$	Total quantity demanded at each bus
$w_k$	Transmission fee charged by the transmission company
$y_k$	The transmission service required by the generator to take energy to desired bus (k) from the hub bus

quest to achieve low carbon electricity.  $E_{akz}$  is the amount of carbon (tonne/MWh) emitted, it varies for each of the different generating sources.  $PC_{akz}$  is the price per tonne of Carbon. In the model, the total tax payable by generator  $z$  located at bus  $k$  and belonging to genco  $a$  is  $CTax_{akz} = PC_{akz} \times E_{akz}$ . In addition, the feed-in tariff ( $RI_{akz}$ ) is earned per MWh of power generated from renewable energy source such as wind and solar. Gencos seek to expand their production capacities in an attempt to increase their profit.  $IC_{akz}$  represents the cost per MW of building new generating facilities.

Due to the existence of market equilibrium and the absence of market arbitrageurs,<sup>1</sup> the total amount of power supplied to each bus is equal to the quantity of power consumed. In this model, the gencos compete in quantities; hence, they decide the quantity of power to sell at each bus and thereafter pay to use the transmission facilities of the transmission company (Transco). The wheeling fee  $w_k$  is the amount charged for transmitting power from an arbitrary hub bus to a bus of interest. The transco seeks to maximize its revenue  $\sum_k w_k y_k$ , while maintaining the limitations placed by the technical capacities of the line.

In the model,  $F_{min_1}$  and  $F_{max_1}$  are the parameters used to represent the technical capacity of the transmission lines. As in [4], we use a linear DC approximation of

<sup>1</sup> Arbitrageurs take advantage of price difference in the market; they buy a product in a place at lower price and sell it in another place where it is worth more.

the AC power flows in the network [18], through the use of Power Transmission Distribution Factor *PTDFs*. The *PTDF* represents the change in power flows on the different lines in the network when one unit of power is injected at each bus in the network.

### 2.3 Mathematical representation of the market problems for each participant

We assume that each market participant maximizes its own profit, which is the difference between its revenue and costs. Increasing profit can be achieved by changing the quantity of items sold, for which capacity may need to be expanded. The market problem for each participant differs; the gencos' and transcos' problems are outlined below.

#### 2.3.1 Genco market problem

Gencos get their revenue from the sale of electricity, and from the renewable feed-in tariff. Substituting in the demand function, this gives:

$$\text{Revenue} = \sum_k \left( \left\{ P_{0k} - \left( \frac{P_{0k}}{Q_{0k}} \right) \sum_a q_{ak} \right\} q_{ak} + \sum_z R I_{akz} p_{w_{akz}} \right) \quad (2.2)$$

The total cost incurred by the Genco is the sum of generation costs, transmission fees, carbon taxes and investment costs.<sup>2</sup>

$$\text{Cost} = \left\{ \begin{array}{l} \sum_{k,z} C_{akz} p_{w_{akz}} + (\sum_m w_m q_{am} - \sum_{k,z} W_k p_{w_{akz}})^+ \\ \sum_{k,z} P C_{akz} E_{akz} p_{w_{akz}} + \sum_{k,z} x p_{akz} I C_{akz} \end{array} \right\} \quad (2.3)$$

The operation of the Gencos is subjected to the following constraints:

1. The power output from each generator cannot be greater than the sum of its maximum capacity, taking into account its capacity expansion.
2. Each generator has a minimum level at which it must operate. The power output cannot be less than this amount.
3. The total sum of the power generated in the network is equal to the total sum of the power demanded at the buses.
4. Regardless of prices, the quantity of electricity demanded at any bus cannot be negative.

<sup>2</sup> For mathematical programming convenience and directionality, the Genco is assumed to pay a positive transmission fee when sending power to any bus from the hub bus and a negative fee when transmitting power from any bus to the hub bus.

Hence, the optimization problem of the Genco can be written as:

$$\begin{aligned}
 &MAX \left[ \sum_m \left\{ \left( P_{Ok} - \left( \frac{P_{Ok}}{Q_{Ok}} \right) \sum_k q_{ak} \right) - w_m \right\} (q_{am}) \right. \\
 &\left. + \sum_{k,z} \{ (RI_{akz} + w_k) - (C_{akz} + PC_{akz} * E_{akz}) \} - \sum_{k,z} xp_{akz} IC_{akz} \right] \tag{2.4}
 \end{aligned}$$

subject to:

$$\begin{aligned}
 \sum_k q_{ak} &= \sum_{k,z} pw_{akz} : \tau_a \\
 pw_{akz} &\leq Gmax_{akz} + xp_{akz} : \beta_{akz} \\
 pw_{akz} &\geq Gmin_{akz} : \gamma_{akz}
 \end{aligned}$$

For all  $q_{ak} \geq 0, xp_{akz} \geq 0$ ; where  $\tau_a, \beta_{akz}, \gamma_{akz}$ , are the dual variables associated with the constraints.

The first-order conditions of this problem are presented in Appendix A.

### 2.3.2 Transco market problem

The transco seeks to maximize its revenue from providing transmission facilities. It acts as a price taker, assuming that it cannot influence the price paid for transmission facilities; hence it maximizes the value of transmission service offered to the generators.

The optimization problem for the transmission company is written as:

$$MAX \sum_k W_k y_k \tag{2.5}$$

where

$$\begin{aligned}
 - \sum_k PTDF_{kl} y_k &\leq Fmin_l : \zeta_{l-} \\
 \sum_k PTDF_{kl} y_k &\leq Fmax_l : \zeta_{l+}
 \end{aligned}$$

$(\zeta_{l+})$  and  $(\zeta_{l-})$  are the dual variables associated with the constraints.

The transco's first order conditions are presented in Appendix B.

## 2.4 Market clearing

Both electricity and transmission markets must clear at all times. Electricity market clearing is implicit in the above; to ensure that all transmission capacity provided is used, we need an additional market clearing condition, specifying that the transmission capacity from each node to the hub is equal to its nodal balance:

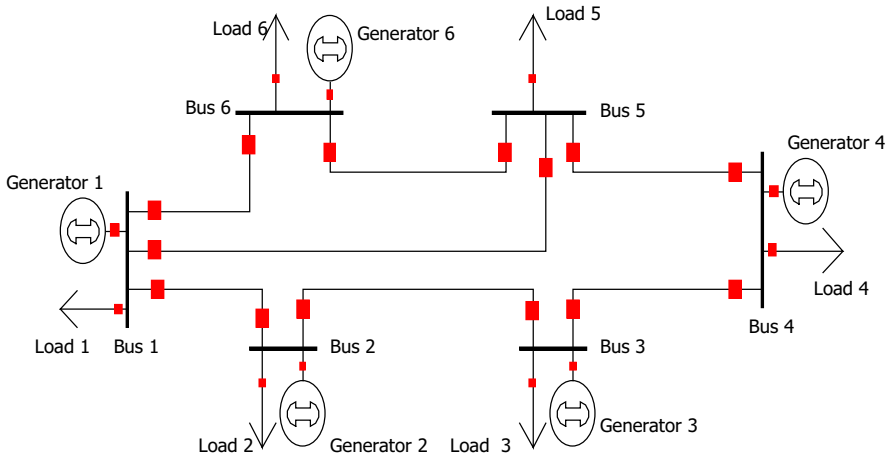


Fig. 1 The IEEE 6-bus network as presented in [17]

$$\sum_a q_{ak} - \sum_{a,z} pw_{akz} = y_k$$

The generating companies (Gencos) and transmission company (Transco) are the market participants.

### 3 Network structure and input data

We apply the model to the IEEE 6 bus network shown in Fig. 1, where we assume that all transmission lines have the same impedance except the line connecting bus 5 to bus 1 which has impedance two times that of the other lines. Generation occurs at all the buses except bus 5. Bus 5 is also the only bus which has a different demand function from the others. The demand function for bus 1,2,3,4 and 6 is  $P(Q) = 150 - 0.096Q$  and for bus 5 is  $P(Q) = 125 - 0.065Q$  ( $Q$  is the quantity of demand). This results in a congestion profile that is representative of real-world networks. The input data to the model is given below. The model built is applied to this network structure.

#### 3.1 Costs and feed-in tariff

Generation and investment costs are listed in Table 2 below. Tax and feed-in levels are consistent with current levels in the United States.

#### 3.2 Cases considered

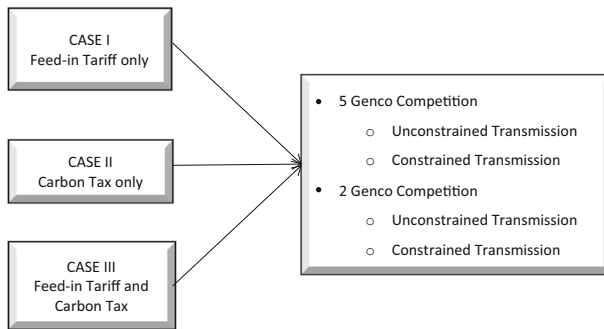
Three cases are considered: when only feed-in tariff is available, when only tax on carbon emission is available and when both carbon tax and feed-in tariffs are available.

**Table 2** Costs and feed-in tariff for the different technologies

	Coal (IGCC)	Gas (Advanced combined cycle)	Wind (offshore)	Solar PV	Nuclear (advanced)
Generating cost (USD/MWh) <sup>a</sup> [20]	38.6	47.5	22.8	11.4	23.6
Investment cost (USD/MWh) <sup>b</sup>	125	125	80	80	71.4
Carbon price (USD/tonne) [13]	12.18	12.18	0	0	0
Emission per technology (tonne/MWh) [19]	0.85	0.48	0	0	0
Feed-in tariff (USD/MWh) [20]	0	0	23	11	0

<sup>a</sup> This value is obtained by adding the fixed and the variable generating costs, assuming a typical generating profile

<sup>b</sup> These values are assumed for the various technologies

**Fig. 2** Schematic representation of the cases considered

To understand the dependence of the Gencos capacity expansion decisions on the number of participating companies and technical conditions of the lines, each of the cases is investigated under four conditions: 5 Genco competition—Constrained and Unconstrained Transmission, and 2 Genco competition—Constrained and Unconstrained Transmission. In total, twelve subcases were investigated. A schematic representation of the cases considered is shown above (Fig. 2).

The demand function at each bus as well as the total initial generation capacity in the system and at each bus is the same for both the 5 Genco and 2 Genco competition. Table 3 and Table 4 below show the initial capacity of each generating company, the generator types and the locations for both competition scenarios. If transmission is unconstrained, the lines have infinite capacity, while for the constrained transmission case, line 61 has a maximum capacity of 50 MW, while the others remain unconstrained.



**Table 3** Generating capacity of each company for 5 Genco competition

	Bus	Generator	Capacity (MW)
Company A	Bus 1	Coal	750
Company B	Bus 2	Gas	750
Company C	Bus 3	Coal	300
	Bus 3	Nuclear	300
Company D	Bus 4	Gas	250
	Bus 4	Nuclear	250
Company E	Bus 6	Nuclear	500
Total			<b>3100</b>

**Table 4** Generating capacity of each company for 2 Genco competition

	Bus	Generator	Capacity (MW)
Company S	Bus 1	Coal	750
	Bus 4	Gas	250
	Bus 6	Nuclear	500
Company T	Bus 2	Gas	750
	Bus 3	Coal	300
	Bus 3	Nuclear	300
	Bus 4	Nuclear	250
Total			<b>3100</b>

## 4 Results and discussion

The results obtained in each of the subcases considered are presented below.

Values for the price of electricity at each bus, the transmission price charged for electricity, the quantity of capacity expansion by each company and the profit of each company are presented in Tables 5, 6 and 7 respectively. All Gencos involved in capacity expansion used renewable technologies.

Feed-in tariffs (Case I) or a combined policy (Case III) do not change electricity prices; in the first case, because feed-in tariffs do not change the marginal cost of electricity production, and in the second case, because changes in marginal costs are offset by changes in oligopolistic mark-ups. The effects of constraining transmission and the transmission company's revenue are also the same for these two cases. As expected, prices are lower under the 5 Genco competition, because a higher level of competition reduces oligopolistic mark-ups.

Under some network conditions, a non-zero transmission fee is charged to producers. As seen in Table 5, congestion affects the various buses differently. Naturally, bus 6 is most affected by a tight constraint on the line supplying most of its power, but effects propagate throughout the network.

Clearly, electricity prices depend only on the demand function at the buses except when congestion of the network occurred. Interestingly, the difference in prices

**Table 5** Electricity price at each bus under the competition scenarios

CASE	Price at each bus (\$/MWh)						Transmission fee charged at each bus (\$/MWh)						Transmission company's revenue (\$/h)
	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	
CASE I feed-in tariff only													
5 Genco constrained	91.31	91.31	91.31	91.31	87.14	91.31	-	-	-	-	-	-	-
5 Genco unconstrained	91.31	91.31	91.31	91.31	87.14	91.31	-	-	-	-	-	-	-
2 Genco constrained	92.79	94.28	95.76	97.25	90.41	103.20	-	2.23	4.46	6.70	8.93	15.62	1115.96
2 Genco unconstrained	100.18	100.18	100.18	100.18	91.84	100.18	-	-	-	-	-	-	-
CASE II carbon tax only													
5 Genco constrained	92.76	93.86	94.96	96.06	92.99	100.46	-	1.32	2.64	3.96	5.28	9.23	659.77
5 Genco unconstrained	99.23	99.23	99.23	99.23	95.06	99.23	-	-	-	-	-	-	-
2 Genco constrained	90.72	93.21	96.16	99.10	93.72	110.88	-	4.42	8.84	13.25	17.67	30.91	2208.96
2 Genco unconstrained	100.18	100.18	100.18	100.18	91.84	100.18	-	-	-	-	-	-	-
CASE III feed-in tariff and carbon tax													
5 Genco constrained	91.31	91.31	91.31	91.31	87.14	91.31	-	-	-	-	-	-	-
5 Genco unconstrained	91.31	91.31	91.31	91.31	87.14	91.31	-	-	-	-	-	-	-
2 Genco constrained	92.79	94.28	95.76	97.25	90.41	103.20	-	2.23	4.46	6.70	8.93	15.62	1115.96
2 Genco unconstrained	100.18	100.18	100.18	100.18	91.84	100.18	-	-	-	-	-	-	-

**Table 6** Capacity expansion by each company under feed-in tariffs only

		5 Genco competition (GW)					2 Genco competition (GW)	
		A	B	C	D	E	S	T
CASE I feed-in tariff only	Constrained transmission	0	0	0.111	0.211	0.211	0.153	0.053
	Unconstrained transmission	0	0	0.111	0.211	0.211	0	0
CASE II carbon tax only	Constrained transmission	0	0	0.006	0.106	0.106	0.088	0
	Unconstrained transmission	0	0	0	0	0	0	0
CASE III feed-in tariff and carbon tax	Constrained transmission	0	0	0.111	0.211	0.211	0.153	0.053
	Unconstrained transmission	0	0	0.111	0.211	0.211	0	0

between the two network conditions is not uniform for all the buses, and does not always vary in an intuitive direction. For instance, for Case II (Carbon Tax Only), under the 5 Genco competition, while bus 1 would have a reduction in price of \$6.47 per MWh, the consumer at bus 6 would experience an increase in price of \$1.23 per MWh between the constrained and unconstrained network conditions. This suggests that the consumers would have significantly different experiences depending on their location in the network.

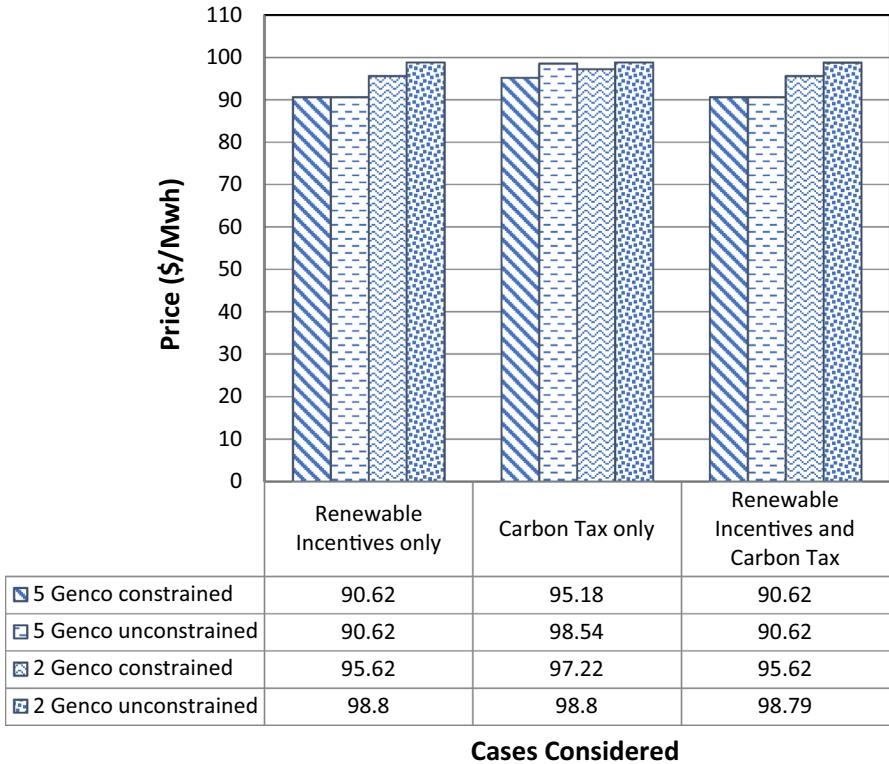
Despite a higher total amount of generation in Cases I and III, the network is not congested under the 5 Genco competition, compared to the 2 Genco competition where network congestion occurred under the constrained network conditions; this shows that higher levels of market power can create congestion.

Case II is different from the other cases. Transmission congestion occurs under the constrained network conditions for both competition scenarios, however, as before, the congestion is higher for the 2 Genco competition. As seen in Table 6 above, capacity expansion only occurred under constrained transmission and was lower than those of Cases I and III. This suggests that the enforcement of carbon taxation only does not necessarily lead to investment in renewable energy or low carbon sources. The technical constraints of the network play a significant role in this case.

The company with the highest existing capacity does not necessarily have the highest profit. Under the 5 Genco competition, Companies A and B, which have the highest joint capacity, rarely have the highest profit. Values from Table 7 show that Company A—which has the highest generation output—is the most profitable company only when carbon tax was not considered. Company's profit depends more on the type of generating technology used. For the 2 Genco competition, Company S which often generated less, had the higher profit in the constrained network. This shows that, especially when fewer companies are involved, the network layout and constraints is of crucial importance in determining the company profitability.

**Table 7** Profit in thousands earned per company under each competition scenario

	5 Genco competition ('000\$)					2 Genco competition('000\$)			Total	
	A	B	C	D	E	Total	S	T		
CASE I feed-in tariff only	Constrained transmission	39.02	32.35	36.93	29.84	35.81	<b>173.96</b>	94.89	90.29	<b>185.18</b>
	Unconstrained transmission	39.02	32.35	36.93	29.84	35.81	<b>173.96</b>	95.62	97.88	<b>193.50</b>
CASE II carbon tax only	Constrained transmission	37.20	33.90	37.41	30.11	37.54	<b>176.16</b>	86.39	90.39	<b>176.78</b>
	Unconstrained transmission	31.92	29.61	34.83	29.54	39.61	<b>165.50</b>	87.05	80.70	<b>167.75</b>
CASE III feed-in tariff and carbon tax only	Constrained transmission	31.26	27.96	33.84	28.38	35.81	<b>157.25</b>	85.66	82.80	<b>168.46</b>
	Unconstrained transmission	31.26	27.96	33.84	28.38	35.81	<b>157.25</b>	86.39	90.39	<b>176.78</b>



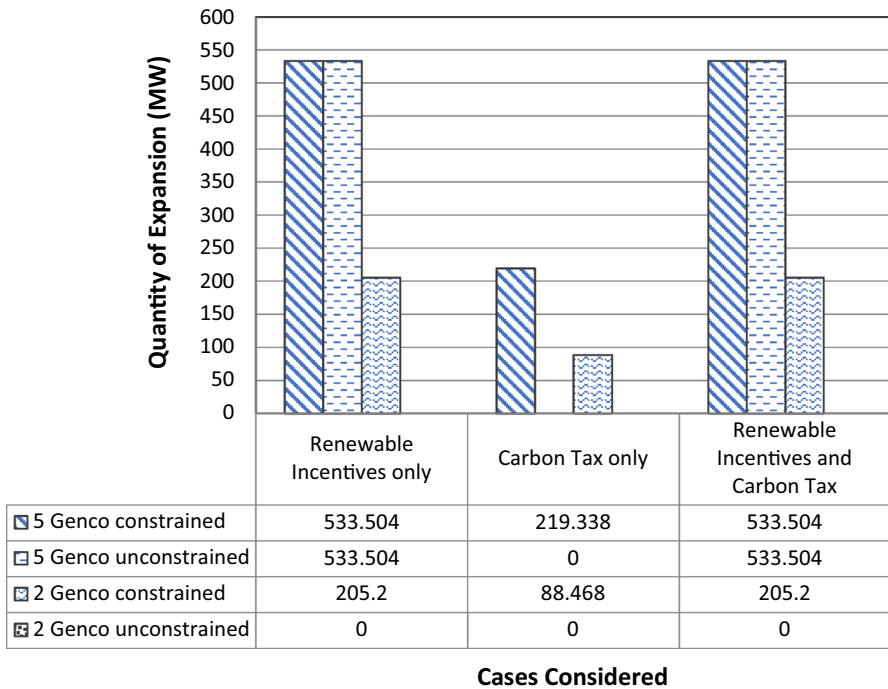
**Fig. 3** Average price of electricity

**4.1 Comparison of results obtained**

As the above section has highlighted, there are important differences between some of the cases considered; we will now look at these in more detail. Figures 3,4,5 compare average electricity prices at the buses, the total investment and the total profit under both constrained and unconstrained network conditions.

*4.1.1 Comparison of average prices*

An average of the unit price of electricity at the buses under the various cases and competition scenarios is presented in Fig. 3 above. It can be seen that the prices are generally lower under the 5 Genco competition, as expected. Somewhat less intuitively, average prices are also often lower in the constrained network. This is an effect of the interaction between market and network conditions, which would never be seen in a perfectly competitive cost minimization model. What happens here is that, as a result of congestion, prices in the (import-constrained) bus 6 increase; some additional investment at bus 6 makes up part, but not all of this increase. However, in the rest of the network, there is now more generation capacity available. This reduces oligopolistic



**Fig. 4** Comparison of total investment under the different cases considered

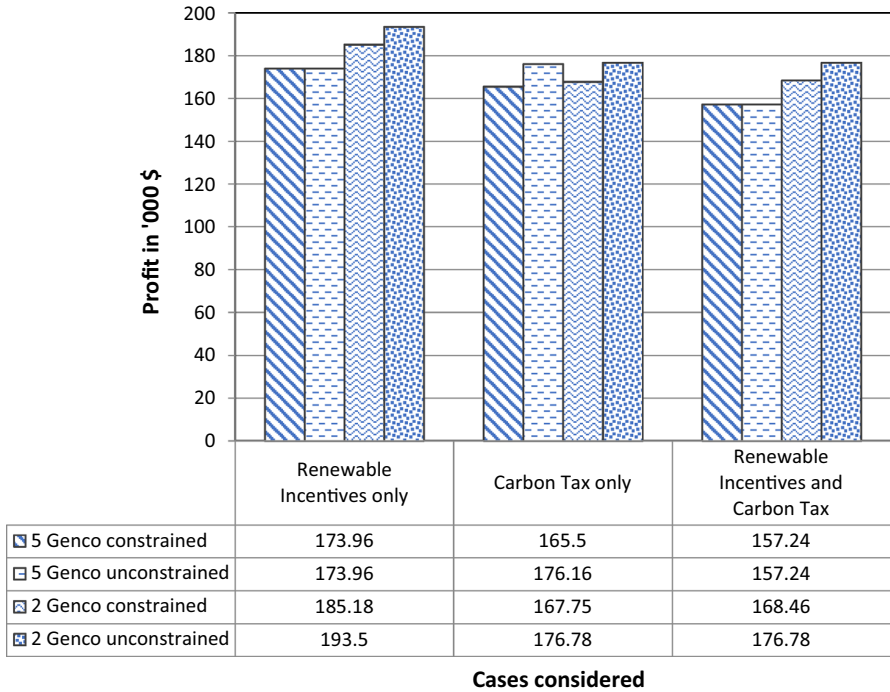
mark-ups and therefore reduces prices. Since demand at bus 6, where prices increase, is low relative to the combined demand at the other buses, average prices decrease with congestion. In effect, partially cutting off part of the network makes the rest of the network more competitive.

From Fig. 3 above, it is seen that electricity price was generally highest when only carbon tax was active. This is because the introduction of carbon tax increased the cost of production for some of the companies. These companies were then able to transfer the cost of the carbon tax imposed on them to the consumer which leads to the increase in price of electricity being noticed. However the average prices were the same and had the highest value for the 2 Genco unconstrained for the three cases. This shows the significant effect of both market power of the gencos and the network conditions on the electricity price.

#### 4.1.2 Comparison of capacity expansion

Figure 4 shows a chart of the values of the capacity expansion for the different cases and competition considered. Both the technical conditions of the lines and the economic incentives influence the quantity of capacity expansion.

The amount of expansion under the 2 Genco competition is significantly less than under the 5 Genco competition in all cases; again, this is expected because the more market power generators have, the more incentives they have to withhold capacity and



**Fig. 5** Comparison of total profits under the different cases considered

raise prices. The quantity of expansion is also lowest for Case II (carbon tax only) and only occurred under the constrained network conditions for both competitions. This suggests that the decision to invest depends significantly on the technical condition of the network and the number of competitors in the market and not entirely on the presence of economic penalties, at least not if these are set at current levels.

Moreover, it is clear that the two policies do not have additive effects; if a feed-in tariff is implemented, an additional carbon tax does not change capacity expansion levels, although it changes profits (as we will see below). A feed-in tariff already stimulates investment in renewables, such that an additional and relatively low carbon tax only increases costs, rather than change investment patterns.

#### 4.1.3 Comparison of profits

With regard to the total profits under the various competition scenarios, the profits under the 2 Genco competition were higher than those under the 5 Genco competition by between 1.36 and 12.43%. This happens both under the constrained and unconstrained network conditions. As mentioned above, the higher profit seen under the 2 Genco competition is a direct result of the large market power generators exercise when fewer competitors are involved [12].

A comparison of the values in Fig. 5 above shows that under the 2 Genco competition, the constrained network had lower profits than the unconstrained network;

a result of the levying of transmission fees and a change in market power. However, under 5 Genco competition, this does not occur, except when only a carbon tax is levied, as this is the only case where transmission congestion occurs.

In the 5 Genco case, the transmission fee was only charged when only carbon tax was active; however, this fee was lower than the fee charged for the 2 Genco competition under same network conditions. Furthermore, this fee was charged under all the constrained network conditions for the 2 Genco competition, although the values were not the same for all the cases considered. This indicates that the Transco benefits more when the generators have more market power.

## 5 Conclusions and policy implications

Previous studies have been carried out on generation capacity expansion under carbon taxes and feed-in tariffs or other renewable incentives [3,9,21]. However, these studies ignore how capacity expansion would depend on the number of the competing firms in an oligopolistic market and on the technical conditions of the network. This paper has addressed these issues.

In this paper, various cases and scenarios are considered to understand how the impact of introducing carbon taxes and feed-in tariffs on the capacity expansion decision of generating companies would depend on the number and size of the competing firms and the technical conditions of the network. This study considers investment when only carbon tax are levied, when only feed-in tariffs are adopted and when both are used at the same time. In each of the cases, four competition scenarios were simulated, namely: 5 Genco competition in an unconstrained network, 5 Genco competition in a constrained network, 2 Genco competition in an unconstrained network and 2 Genco competition in a constrained network. The price of electricity and the profits of the companies were also analysed.

The electricity market is modelled as a mixed complementarity problem where the companies compete in quantities (Nash–Cournot). This stylized model is then applied to a six-bus network. The model built and used for this research has certain intrinsic qualities: it incorporates the technical characteristics of the electricity network, and represents the market conditions better than a simple cost minimization model. It is still heavily simplified and stylized, but key insights can be drawn from it that we expect to also hold true in larger models.

The most important conclusion is that the effect of a policy such as carbon tax or feed-in tariff depends more on the technical conditions of the network and the number of competitors in the market than on anything else. As such, no two countries can experience the same effects from such a policy if their electricity markets or networks are different. The quantity of capacity expansion also depends significantly on the number of competitors in the market. For instance, under carbon taxation only, capacity expansion only occurred under the constrained network conditions for both competitions; however, the quantities were lower than those of other economic conditions. It was also observed that when the competition intensity is higher consumers benefit more from capacity expansion because it leads to a higher electricity supply and lower electricity prices.



Interestingly, there are also important interactions between the technical conditions of the network and the market organization. These are not always intuitive; for instance, average electricity prices may decrease with network congestion. This again underlines the importance of a thorough country-specific analysis to inform energy policy.

Providing incentives for renewables without carbon taxation does not take into account the negative impacts of carbon on the environment although it encourages production from low carbon sources. Incentivising renewables and carbon taxation combines the advantages of both. It takes into account the negative effect of carbon and encourages production from low carbon sources. However, in our model, adding a carbon price to a market where a feed-in tariff is already present only serves to reduce generator profits, rather than leading to additional investment or lower prices.

Naturally, our results are specific to the network setting we have analysed, and to the (relatively low) current levels of renewable support and carbon prices. However, we expect the general qualitative conclusions above to carry over to larger models.

Further research is needed to analyse the quantitative effects of feed-in tariffs and carbon prices in specific oligopolistic markets. Further research should also address how investment would be spread out over a longer period. This would be useful to determine the long-term effects of the various policies designed to achieve low carbon electricity sector.

To improve the current model, certain characteristics such as variable generation output over various times of the day, variable marginal cost, the presence of arbitrageurs and energy storage mechanisms can be incorporated. This would enhance the model's ability to represent future power networks and improve the quality of result obtained; however, it would also increase the computational complexity of the model.

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## Appendix A: Generating companies problem

The Lagrange equation of the optimization problem of Generating Companies (Gen-cos) is written as:

$$\begin{aligned}
 L(pw, q, xp, \tau, \beta, \gamma) = & \left\{ \left( P_{Ok} - \left( \frac{P_{Ok}}{Q_{Ok}} \right) \sum_k q_{ak} \right) - w_m \right\} (q_{am}) - xp_{akz} * IC_{akz} \\
 & + \{ (IR_{akz} + w_k) - (C_{akz} + PC_{akz} * E_{akz}) \} pw_{akz} + \tau_a (pw_{akz} - q_{ak}) \\
 & + \beta_{akz} (pw_{akz} - xp_{akz} - Gmax_{akz}) + \gamma_{akz} (Gmin_{akz} - pw_{akz}) \quad (A1)
 \end{aligned}$$

The first order conditions for the optimization problem are:

1 With respect to  $pw_{akz}$

$$\begin{aligned} \frac{\delta L}{\delta(pw_{akz})} &= \{(IR_{akz} + w_k) - (C_{akz} + PC_{akz} * E_{akz}) + \tau_a - \beta_{akz} + \gamma_{akz}\} \leq 0 \\ pw_{akz} &\geq 0 \\ pw_{akz}\{(IR_{akz} + w_k) - (C_{akz} + PC_{akz} * E_{akz}) + \tau_a - \beta_{akz} + \gamma_{akz}\} &= 0 \end{aligned} \tag{A1.1}$$

2 With respect to  $q_{ak}$

$$\begin{aligned} \frac{\delta L}{\delta q_{ak}} &= \left\{ \left( P_{ok} - \left( \frac{P_{ok}}{Q_{ok}} \right) (2q_{ak} + \sum_{a \neq b} q_{bk}) - w_m - \tau_a \right) \right\} \leq 0 \\ q_{ak} &\geq 0 \\ q_{ak} \left\{ \left( P_{ok} - \left( \frac{P_{ok}}{Q_{ok}} \right) (2q_{ak} + \sum_{a \neq b} q_{bk}) - w_m - \tau_a \right) \right\} &= 0 \end{aligned} \tag{A1.2}$$

3 With respect to  $xp_{akz}$

$$\begin{aligned} \frac{\delta L}{\delta(xp_{akz})} &= \{-IC_{akz} + \beta_{akz}\} \leq 0; \\ xp_{akz} &\geq 0 \\ xp_{akz}\{-IC_{akz} + \beta_{akz}\} &= 0 \end{aligned} \tag{A1.3}$$

4 With respect to  $\beta_{akz}$

$$\begin{aligned} pw_{akz} - Gmax_{akz} - xp_{akz} &\leq 0 \\ \beta_{akz} &\geq 0 \\ \beta_{akz}(pw_{akz} - Gmax_{akz} - xp_{akz}) &= 0 \end{aligned} \tag{A1.4}$$

5 With respect to  $\gamma_{akl}$

$$\begin{aligned} Gmin_{akz} - pw_{akz} &\leq 0 \\ \gamma_{akz} &\geq 0 \\ \gamma_{akz}(Gmin_{akz} - pw_{akz}) &= 0 \end{aligned} \tag{A1.5}$$

6 With respect to  $\tau_a$

$$\sum_k q_{a,k} - \sum_{k,z} pw_{akz} = 0 \tag{A1.6}$$

Equations (A1.1) to (A1.6) form the KKT conditions which were implemented in AIMMS to represent the Genco Market Problem.

## Appendix B: Transmission company's problem

The first order (KKT) conditions for the optimization problem of Transmission Company's is derived from the Lagrange multiplier and presented below.

1 With respect to  $\zeta_{l+}$

$$\begin{aligned}\frac{\partial L}{\partial(\zeta_{l-})} &= F\min_l + PTDF_{kl} * y_k \leq 0 \\ \zeta_{l-} &\geq 0 \\ \zeta_{l-} (F\min_l + PTDF_{kl} * y_k) &= 0\end{aligned}\quad (B1.1)$$

2 With respect to  $\zeta_{l+}$

$$\begin{aligned}\frac{\partial L}{\partial(\zeta_{l+})} &= F\max_l - PTDF_{kl} * y_k \leq 0 \\ \zeta_{l+} &\geq 0 \\ \zeta_{l+} (F\max_l - PTDF_{kl} * y_k) &= 0\end{aligned}\quad (B1.2)$$

3 With respect to  $y_k$

$$\frac{\partial L}{\partial(y_k)} = w_k + PTDF_{kl}(\zeta_{l-} - \zeta_{l+}) = 0 \quad (B1.3)$$

Equations (B1.1), (B1.2), (B1.3) are implemented in AIMMS to represent the transmission company's problem.

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