Market failure caused by wind-power integrations in a competitive electricity market with transmission congestions

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Abstract

I investigate the market equilibrium of a competitive electricity market with significant wind-power penetration when transmission congestion is expected to occur. Specifically, I build a two-stage stochastic model to simulate the forward and spot electricity markets. The stochastic model captures the impacts of wind-energy uncertainty when a transmission line is expected to be congested in a forward electricity market. The proposed model considers conventional generators' ramp rates as well as grid topology. I conclude that integrating wind power into a grid system either brings overconsumption of electricity or leads FTR holders to pursue high FTR entitlement by generating electricity when the market price is less than their marginal generation costs. Both of the two effects lead the market equilibrium to deviate from the social optimum. The implementation of real-time retail price or carbon tax will aggravate the inefficiency. In contrast, if FTR holders have market power in the electricity market, the inefficiency caused by integrating wind power is less than when the market is completely competitive.

Keywords: Consumer Risks, Financial Transmission Right, Wind Power, Stochastic Market Model, Transmission Congestion

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1. Introduction

Integration of wind power into an electricity grid causes fundamental challenges to transmission congestion management in current power systems. Wind-forecast errors can lead to incorrect predictions about transmission-network congestions. For example, the anticipated congestion of a line might fail to occur as expected because of an unpredicted wind-energy shortfall. However, the efficiency effects of wind-power integration into a market with transmission congestions have not been comprehensively examined.

In this paper, I model strategies for both the supply and demand sides in a competitive market when wind power is integrated into the grid system and transmission congestions are expected to occur. In order to capture the effects of the wind-energy uncertainties, I use a two-stage stochastic framework to examine the impacts of wind-energy uncertainty in both the forward and the spot markets.

Existing studies use one-stage, static models to examine the environmental impacts of transmission congestions and the performance of the FTR policy (Palmer and Burtraw, 2005; Bushnell, 1999; Cardell et al., 1997; Gu and Xie, 2014). To simulate a market without wind power, static models work well because the congestion uncertainty is small.

However, a static model cannot adequately reflect the effects of the significant supply-side uncertainty caused by using wind power. For example, the static model cannot be used to examine the arbitrage opportunity caused by forecast errors of transmission congestions. In fact, rational market participants seek to maximize the overall profit in all sequential markets; therefore they will include the the effects of congestion uncertainty caused by wind power into their day-ahead decision-making. The static model, which simulates a one-stage market, is insufficient to simulate participants' decision behaviors in a sequential-market system. Furthermore, the static model cannot be used to measure the risks caused by unexpected real-time events (FERC, 2012).

Therefore, I adopt a multi-stage, stochastic framework to assess the impacts of wind-energy uncertainty on the market equilibrium in both the forward and spot markets. A detailed stochastic framework is considered in Section 2. Under the stochastic framework, the social optimization problem is to maximize the expected total social surplus while considering wind-energy uncertainty. Compared with static models, the stochastic model is able to measure the risks caused by the interaction between wind-energy uncertainty and transmission congestions.

The analyses in this research also examine the impact of grid topologies. I first analyze the interaction between wind-power uncertainty with transmission congestion in a two-node network. In the appendix, I repeat the analyses in a three-node loop network. The results demonstrate that market failure caused by using wind power occurred in both two networks. The conclusions based on these two networks can be generalized to more complicated grid networks Joskow and Tirole (2000).

The analyses demonstrate that the market equilibrium deviate from the social optimum when the wind power producers (WPPs) are defined as capacity resource (CR). When the WPPs are CR, they must participate in the day-ahead forward market and make generation commitment. If a WPP's generation is less than its commitment level, the WPP must purchase electricity from the real-time spot market to fill the gap between its generation and commitment level. In this scenario, the demand side will overconsume electricity because the price in the spot market does not affect consumers' utility function.

When the WPPs are not defined as CR, the "financial transmission right" (FTR) policy will fail by the interaction of wind-energy uncertainties and transmission congestions. The FTR policy is a broadly used policy by system operators (SOs) to hedge against price risks caused by transmission congestion (Hogan, 1992, 1993). In current markets, the demands are cleared according to local marginal prices (LMPs). Once a transmission line is congested, the SO will receive more money from consumers than the amount needed to pay suppliers. The net surplus is called the "SO's merchandising surplus". The FTR policy is used to pro rata allocate the "SO's merchandising surplus" for FTR holders in the day-ahead market(O'Neill et al., 2002). The day-ahead market is a forward market occurring one day ahead of the demand. The success of the FTR policy relies on two factors: the first is the ability of FTR entitlements to adequately hedge against price risks caused by transmission congestion, and the second is the FTRs' distribution that has no impact on the equilibrium of the electricity market (Deng et al., 2010; Joskow and Tirole, 2000). In addition to being used to hedge against congestion charges, FTRs also impact investors decisions regarding electricity grid investments (Hogan et al., 2010; Joskow and Tirole, 2005; Mount et al., 2011; Schill et al., 2011; Brennan, 2006). Results from static models demonstrate that the FTR policy performs well when the market is fully competitive (Joskow and Tirole, 2000).

In contrast, the analyses based on the stochastic framework indicate that transmission-line users have incentive to overbid in the forward market for a higher expected FTR entitlement. Consequently, overconsumption of electricity occurs, and the wind-energy utilization level is insufficient.

The remainder of the paper is organized as follows: the two-stage power market model is described in Section 2; in Section 3, I analyze the social optimum when a transmission congestion occurs in a electricity market with wind power; then, Section 4 examines the market failure when WPPs are not CR; Section 5 analyze the failure of the FTR policy when WPPs are CR; Section 6 present the impact of implementing two counter factual policies, which are the real-time retail price and the carbon tax; lastly, in Section 7, I draw final conclusions.

2. Power market model in a two-node model

2.1. Model Setup

In this research, the electricity-market model is made up of four elements: a sequence of markets, the topology of the transmission grids, the market participants, and the procedure for bidding and dispatch.

Sequence of Markets. my market model is a two-stage stochastic model, with both a day-ahead market ($t = a$, DA) and a real-time market ($t = r$, RT) (Varaiya et al., 2011; Rajagopal et al., 2012; Meyn et al., 2010). In the DA market, a generation plan is scheduled for each hour of the next day. In the RT market, which usually occurs an hour ahead of the real dispatch, the generation plan can be adjusted. In each of theses two markets, aggregate demand and electricity generation must be balanced. Prior to the RT market settling, I assume that any uncertainty about supply and demand is resolved.

Network Topology. I study a two-node grid model shown in Fig. 1. I us a DC-power flow model and assume that the grid's transmission capacity is K MWh per hour. In the Appendix, I repeat the analysis in a three-node loop model. The two networks together capture the qualitative behavior in most networks(Rajagopal et al., 2014).

Market Participants. On the demand side, I assume that consumers are located in Node 2, which is the power-importing region. Consumers' aggregate utility function is $u_d(Q)$, and the aggregate

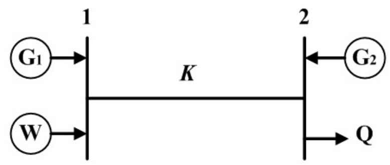

Figure 1: Two-Node Model

inverse demand function is $p(Q)$. Here, Q MWh is the total electricity consumption. Because I focus on the impacts of supply-side uncertainty, I assume that both these two functions are revealed in the DA market.

On the supply side, this research considers three electricity-generating companies (GenCos): wind power producers(WPPs), a GenCo with slow-ramp generators G_1 and a GenCo with fast-ramp generators G_2. I use W to represent the wind-energy generation level. G_i's generation cost is $c_i(q)$, which is a differentiable and convex function. G_1 and WPPs are located in Node 1, which is the power-exporting region. G_2 is co-located with consumers in Node 2. I assume the marginal cost of G_1 is much lower than that of G_2, such that $c_1^{'}(K) < c_2^{'}(q)$ for all q. Therefore, without integrating wind power into the grid, the transmission line will be congested when the demand is higher than K.

I use G_1 to represent the GenCo with slow-ramp generators and assume its aggregate cost function is $c_1(q)$. G_1's generation is scheduled in the DA market and cannot be adjusted in the RT market. G_1 and wind power producers (WPPs) are located in Node 1, which is the power-exporting region. G_2 is the GenCo with fast-ramp generators, and its generation cost is $c_2(q)$. G_2's generation level can be adjusted to any level in the RT market. I assume that G_2 is co-located with consumers in Node 2. Both $c_1(q)$ and $c_2(q)$ are differentiable and convex functions.

Procedure of Bidding and Dispatch. In the DA market, consumers submit their inverse demand curve, while conventional GenCos submit their generation bidding curve. All market participants know the forecast for the wind-energy generation and the distribution of the forecast error. The SO schedules the DA-generation plan according to the demand curve, the bidding curve of GenCos, and the wind-energy forecast. The generation level of a GenCo according to the DA plan is called "the DA commitment" from the GenCo. I denote G_i's DA commitment by q_i^a. In the RT market, the SO also schedules additional generation from conventional GenCos if the total electricity generation is less than the demand due to the insufficient wind-energy generation. The additional generation from G_i in the RT market is denoted by q_i^r. I use $q_i = q_i^a + q_i^r$ to represent G_i' generation. I assume G_1's DA commitment level cannot be adjusted in the RT market because G_1's generators are slow-ramp. Consequently, the SO can only use G_2 to compensate for unexpected wind-energy shortfalls. Therefore, I can conclude that $q_1^r = 0$ and $q_1 = q_1^a$. I use p_i^a to represent the DA LMP of Node i, and p_i^r is the RT LMP of Node i.

WPPs are allowed to only participate in the RT market and be paid by the RT LMPs if the WPPs are not defined as the capacity resource(Porter et al., 2012). In this scenario, the WPPs will not make a generation commitment in the DA market and can produce to any level that they wish. Wind-energy generation would be curtailed only when the transmission line is congested. I then examine the scenario in which the WPPs are defined as the capacity resource and are required to make generation commitments in the DA market.

Although this framework is highly simplified, it captures the essential problems caused by integrating wind energy into the grid. The important conclusions deduced from this model can still carry over in the presence of any radial framework. In addition, because the main goal in my study is to analyze congestion uncertainties, I do not account for transmission losses nor generation-capacity limits.

2.2. Allocation of FTRs

I assume that the FTRs are allocated before the DA market. The proportions of FTRs allocated to G_1, G_2, and the WPPs are α_1, α_2 and α_w, with $\alpha_1 + \alpha_2 + \alpha_w = 1$. I use Θ to represent the "SO's merchandising surplus". The product of Θ and the proportion of the FTRs held by a participant is the profit of the holders from holding the FTRs.

According to the definition of "SO's merchandising surplus", Θ is equal to the total payment of consumers in two stages, minus the total money received by the power plants for electricity generation. In current markets, the FTR policy is used to hedge against DA-congestion charges. The entitlement is calculated according to the DA LMPs, and it is allocated to holders after the DA-generation plan has been determined. I analyze the scenario that simulated the current markets. I also examine the scenario in which the amount of the FTRs' entitlement is adjusted according to the RT LMPs because the unpredicted wind-energy insufficiency can influence the amount of the

"SO's merchandising surplus".

In my two-node model, the electricity flows from Node 1 to Node 2. I use f^a_{12} to represent the DA-scheduled power flow in the transmission line and f^r_{12} to represent the RT power flow in the transmission line. Here, the DA dispatch results in an FTR entitlement with amount $f^a_{12}(p^a_2 - p^a_1)$. In the RT market, the power flow from Node 1 to Node 2 is f^r_{12}, and the incremental FTR entitlement is $(f^r_{12} - f^a_{12})(p^r_2 - p^r_1)$. Thus, I have the following definition while I include the effect of the RT unpredicted wind-energy insufficiency in my model.

Definition The expectation of the "SO's merchandising surplus' is denoted by

$$\Theta = f^a_{12}(p^a_2 - p^a_1) + E[(f^r_{12} - f^a_{12})(p^r_2 - p^r_1)]. \tag{1}$$

The amount of Θ will be pro rata allocated to holders of FTRs.

3. Electricity dispatch and socially optimal market equilibrium

DA Dispatch. In the DA market, the consumers submit their aggregate utility function $u_d(q)$ to the SO. Conventional generators also must submit their committed generation to the SO. G_1 decides on its committed generation to maximize its expected net profit.

$$\max_{q_1} p^a_1 q_1 - c_1(q_1) + \alpha_1 \Theta. \tag{2}$$

G_1's net profit has two components: the first is the net benefit from power generation and the second is the expected benefit from the entitlements of FTRs. When the FTR policy is not implemented in the power system, or G_1 holds no FTR, the value of α_1 is equal to 0. In this case, the profit function of G_1 only includes the generation profit part.

From Problem (2), I can directly get the following proposition about the bidding strategy of G_1.

Theorem 3.1. *In the DA market, the optimal bidding strategy of G_1 must satisfy the following condition:*

$$c_1\prime(q_1) = p_1^a + \alpha_1 \frac{\partial \Theta}{\partial q_1}. \tag{3}$$

If G_1 has no capability to influence Θ or manipulate the market price, G_1's bidding curve is its marginal cost curve.

G_2's bidding is similar to G_1's bidding. When the GenCos' bidding curves are their marginal cost curves, the SO's DA-dispatch maximizes the expected total social net profit by solving

$$\begin{aligned} &\max_{q_1, q_2^a} E[u_d(q_2^a + q_2^r + \min\{W + q_1, K\}) - c_1(q_1) - c_2(q_2^a + q_2^r)] \\ &s.t.\text{: } q_1 \leq K. \end{aligned} \tag{4}$$

I use λ to represent the Lagrange multiplier of the constraint of Problem (4). By solving Problem (4),I have the following theorem.

Theorem 3.2. *If the GenCos have no capability to manipulate LMPs and impact the probability of transmission congestion, the DA optimal dispatch schedule for Node 1 must satisfy the following condition:*

$$c_1\prime(q_1) + \lambda = E[c_2(q_2^a + q_2^r)\boldsymbol{1}(q_1 + W < K)]. \tag{5}$$

In addition, $q_2^a \in [0, \hat{q}_2]$ is the optimal dispatch set for Node 2. Here, $\hat{q}_2$ satisfies the condition $u_d\prime(\hat{q}_2 + K) = c_2\prime(\hat{q}_2)$.

The right-hand side of Condition (5) reflects how the change of G_1's commitment q_1 affects the expected RT LMP of Node 2, as well as the DA-market equilibrium. Therefore, I have the following definition.

Definition The G_1's residual inverse demand (RID) curve to G_1 is defined as

$$p_2^r(q_1) = E[c_2(q_2^a + q_2^r)\mathbf{1}(q_1 + W < K)]. \tag{6}$$

RT Dispatch. In the RT market, all market players observe the available wind energy W. The market-clearing problem is a deterministic optimal power flow (OPF) problem. According to Joskow and Tirole (2000), as the market is completely competitive, the FTR policy has no impact on the equilibrium of the power market. By solving the OPF problem, I conclude that the market equilibrium in the RT market equilibrium is expressed as the following:

$$q_2 = \begin{cases} q_2^r : c_2\prime(q_2^a + q_2^r) = p(K + q_2^a + q_2^r), & \text{if } q_1 + W \geq K, \\ q_2^r : c_2\prime(q_2^a + q_2^r) = p(q_1 + W + q_2^a + q_2^r), & \text{if } q_1 + W < K, \end{cases} \tag{7}$$

$$p_2^r = c_2\prime(q_2^a + q_2^r), \tag{8}$$

$$p_1^r = \begin{cases} 0, & \text{if } q_1 + W \geq K, \\ p_2^r, & \text{if } q_1 + W < K, \end{cases} \tag{9}$$

The WPPs' generation level w is

$$w = \min\{W, K - q_1\}. \tag{10}$$

4. Market failure when WPPs are not CR

When the WPPs are defined as CR, they need to commit their generation in the DA market. The profit maximization problem of the WPPs is

$$\max_{\bar{w}} p_1^a \bar{w} - E[p_2^r(\bar{w} - W)_+] + \alpha_w \Theta\}. \tag{11}$$

Here, $\bar{w}$ is the WPPs' commitment level. The optimal commitment strategy for the WPPs is solved from the above problem and expressed in the following theorem.

Theorem 4.1. *In the day-ahead market, the WPPs' optimal commitment strategy must satisfy*

$$p_1^a + \alpha_w \frac{\partial \Theta}{\partial \bar{w}} = \frac{\partial E[p_2^r(\bar{w} - W)_+]}{\partial \bar{w}}. \tag{12}$$

According to the dispatch protocol used in most markets, the SO will commit $q_1 = K - \bar{w}$ from G_1 and $q_2^a = \hat{q}_2$ from G_2 in the DA market such that $p_2^a = c_2\prime(q_2^a) = u_d\prime(\hat{q}_2 + K)$. Then, the DA LMPs are calculated according $p_i^a = c_i\prime(\hat{q}_2)$. The consumers will pay p_2^a for the amount of $K + \hat{q}_2$, and the DA entitlement of the FTRs is $K(p_2^a - p_1^a)$. The DA market is the same as the social optimum solved in Eq. 4.

However, the RT market equilibrium is different from the social optimum. In the real-time market, if W is less than the commitment level $\bar{w}$, WPPs need to buy the quantity of $\bar{w} - W$ from G_2 by price p_2^r. Therefore, the total consumption level in the RT market is $K + q_2^a$ even if the WPPs have insufficient generation level. Consequently, the total consumption level in this scenario is higher than the socially optimal consumption level described in Eq. 7.

5. The failure of the FTR policy when the WPPs are not CR

5.1. Consumers' optimal strategy when the WPPs are not CR

When the WPPs are not CR, they do not need to make generation commitment in the DA market. Instead, they can determine their generation levels in the RT market, in which the available wind-energy generation level is know. Thus, the WPPs face fewer risks in this scenario than when they are defined as CR. Because the WPPs sell energy in the RT market, consumers have opportunity to buy electricity at a low price in the RT market. Consequently, rational consumers will only buy electricity from the DA market to satisfy parts of their total demand.

Therefore, in my model, the consumers' optimal strategy is not to purchase all their needed energy in the DA market and hold a part of their energy order to purchase from the WPPs at a lower price in the RT market.

With considering the wind-power uncertainty, the consumers' optimal strategy in the DA market is to buy electricity from G_1 upto q_1^a that satisfy Condition 5 and buy $q_2^a \in [0, \bar{q}_2]$ from G_2. Here, $\bar{q}_2$ satisfies $c_2\prime(\bar{q}_2) = c_1\prime(q_1^a)$. In the RT market, consumers will purchase additional electricity from the WPPs and G_2 according to Conditions 7-10. If the FTR policy is not implemented in the market or G_1 does not have any FTRs, the market equilibrium in both the DA and RT markets are the same as the social optimum.

However, G_1's biding curve is different from its marginal cost curve if the FTR policy is implemented in the market and G_1 holds some FTRs. Therefore, the market equilibrium in the DA market is different from the social optimum when G_1 hold parts of FTRs. Furthermore, the distribution of the FTRs will influence the market equilibrium of the electricity system. Consequently, the FTR policy fails.

5.2. Impacts of the FTR policy on the DA bidding: Encouraging Bidding Effect (EBE)

(Joskow and Tirole, 2000) shows the FTR policy has no impact on the market equilibrium if no participant has market power and there are no uncertainties on the supply side. However, when the WPPs is not defined as CR, G_1's bidding strategy is connected with the amount of FTRs owned by G_1, even if the electricity market is fully competitive. At the same time, the FTR holders is exposed to a risk of loosing all entitlement.

According to the analyses in 5.1, the DA LMPs of the two nodes are the same, and the day-head entitlement to FTR holders is zero. Therefore, the FTR entitlement in the A market is zero. If wind energy W is sufficient to congest the transmission line, the term $(f^r_{12} - f^a_{12})$ in Definition 1 is $K - q_1$ and the incremental congestion charges is $(K - q_1)(p^r_2 - p^r_1)$. Because p^r_1 is zero when the transmission line is congested, the entitlement allocated to FTR holders is $(K - q_1)p^r_2$. For the entitlements to FTR holders, I have the following corollary:

Corollary 5.1. *If the DA $q_1 < K$, the DA entitlements to FTR holders equal zero, even though the line is expected to be congested in the RT market. As a result, the total expected entitlements to FTR holders is*

$$\Theta = E[(K - q_1)p^r_2 \boldsymbol{1}(q_1 + W \geq K))]. \tag{13}$$

In the RT market, if the wind energy W is insufficient to congest the transmission line, there is no congestion charges in both DA and RT markets. Consequently, the FTR holders cannot get the entitlement even if the shadow price of the transmission constraint in the DA market is positive. Therefore, the FTR holders are exposed to a risk of loosing all FTR entitlement. If the GenCos at the energy-exporting region hold FTRs, they have incentive to reduce the risk of loosing all FTR entitlement by committing more generation in the DA market.

In my model, if G_1 owns some FTRs, then its bidding curve can deviate from its marginal cost curve even if it does not have market power. In fact, the optimal bidding strategy of G_1 must satisfy the condition in Theorem 3.1 in Section 3.Then,

Definition I denote

$$\theta = \frac{\partial \Theta}{\partial q_1} \tag{14}$$

as the marginal expected FTR entitlement to G_1.

Therefore, G_1's optimal bidding strategy is:

$$c_1\prime(q_1) = p_1^a + \alpha_1 \theta. \tag{15}$$

According to Corollary 5.1, I have

$$\theta = \frac{\partial E[(K - q_1) p_2^r \mathbf{1}(q_1 + W \geq K)]}{\partial q_1}. \tag{16}$$

According to Eq. (13), Θ is a function of the probability of transmission congestion. Hence, $\theta \neq 0$ when G_1 can impact the probability of transmission congestion. If $\theta > 0$, G_1's one more unit of generation commitment in the DA market can bring itself the higher expected FTR entitlement; therefore, G_1 being given a proportion of FTRs can increase its willingness to supply. As a result, for any given price, G_1's committed generation is higher than in the situation where G_1 does not hold any FTRs. Thus, the bidding process will not reveal the true marginal cost curve to the SO. The commitment level depends on how many FTRs G_1 holds. In the following theorem, I rigorously state the relation between the commitment equilibrium in the DA market and the proportions of FTRs held by G_1.

Theorem 5.2. *If $\theta > 0$, more FTRs held by G_1 can encourage G_1 to commit more with the same price in the DA market.*

In Fig. 2, I conceptually show G_1's commitment strategy when it holds some FTRs and $\theta > 0$. Without holding FTRs, the marginal benefit curve for G_1 is p_1 (shown as the horizontal red line),

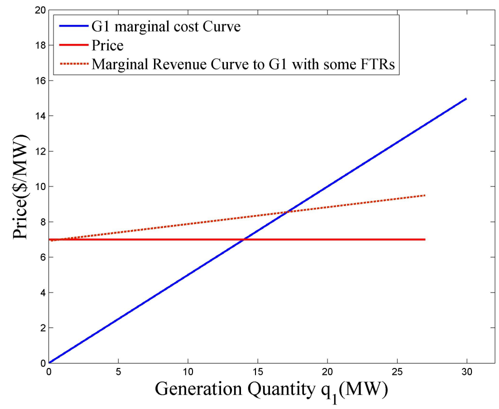

Figure 2: Marginal Revenue to G_1 is Changed by Introducing FTRs into the System

which is the market price; after G_1 obtains α_1 proportion of FTRs, G_1's marginal-benefit curve is $p_1 + \alpha_1\theta$ (shown as the dashed red line). Holding FTRs raises G_1's marginal benefit curve and provides it an incentive to bid more.

The above analysis suggests that the expected revenue from holding FTRs subsidizes G_1's DA commitment. Consequently, the SO schedules more electricity generated by G_1, and the DA LMP of Node 1 is lower. Thus, I have following definition:

Definition G_1 holding some FTRs encourages G_1 to make a higher commitment level in the DA market. I call this effect FTRs' **Encouraging Bidding Effect (EBE)**.

5.3. Numerical Example for the EBE

To examine the EBE, I design a numerical example. In the EBE numerical example, I assume that G_1 owns coal-fired generators and its marginal cost is \$16/MWh, while G_2 owns fast ramp gas-fired generators and its marginal cost is \$40/MWh. I assume all FTRs are allocated to G_1. I also assume the transmission capacity is 728 MWh and the demand in Node 2 is 1500 MWh. Wind power W yields a normal distribution with the mean 500 MWh and the standard deviation 100 MWh. I assume that there is a \$30/MWh subsidy to WPPs in addition to the LMPs.

In Fig. 3, I present calculation results from my numerical experiment. In the figure, the G_1' RID curve is the black line, which is calculated according to Definition 6. Without the EBE, G_1's bidding curve is its marginal cost curve, which is the red line. G_1 will not produce electricity until the market price is higher than P_{noEBE}. When the price is equal to, or higher than P_{noEBE}, G_1

will supply electricity to any level. For the equilibrium of the DA market, Q_{1noEBE} will be cleared at P_{noEBE}.

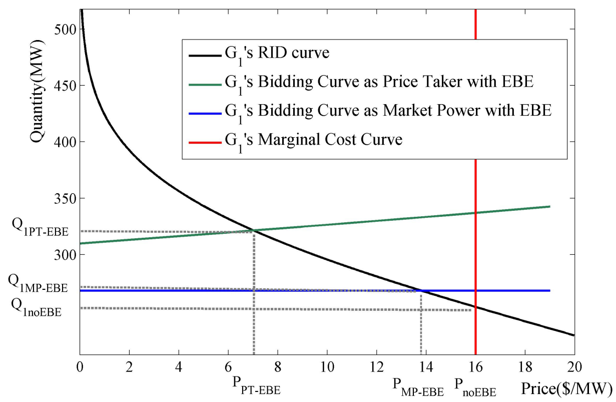

Figure 3: Strategic Bidding Curve of G_1 and Its Marginal Cost Curve

With the EBE, G_1's bidding curve, which is the green line, deviates from its marginal cost curve. The equilibrium price in the DA market will decrease to P_{PT-EBE}, which is less than P_{noEBE}; the DA-commitment level, which is also G_1's generation level, will increase to Q_{PT-EBE}.

In Table 1, the market outcomes both with and without EBE are summarized in Columns 1 and 2. Without EBE, the DA-market price in Node 1 is \$16/MWh and the DA-commitment level with G_1 is 253.3 MWh. With EBE, the DA-market price in Node 1 decreased to around \$7/MWh, which is 56.2% less than \$16/MWh; correspondingly, the DA commitment level with G_1 increases to 321.5 MWh, which is about 26.9% higher than 253.3 MW.

Interestingly, although the expected FTRs' entitlements subsidize G_1's bidding in the DA market, G_1's net profit (\$10522) is lower when EBE occurs than when there is no EBE scenario(\$11392). This is because G_1 does not have market power in the electricity market. For example, G_1 is a group of completely competitive GenCos. Then the competition forces G_1 to commit when the marginal expected benefit from bidding is higher than its marginal cost. When EBE occurs, the market price (\$7/MWh) is lower than G_1's marginal cost, but the sum of the market price and the expected marginal FTR entitlement is equal to G_1's marginal cost. Hence, the subsidies from expected FTRs' entitlements encourage G_1's bidding even when the price is lower than its marginal costs.

The EBE discourages the utilization of wind energy because a higher commitment level of G_1 leaves less transmission capacity for the wind generator. From Table 1, the expected wind-power generation is 466.2 MWh when there is no EBE; this can be compared to 397.1 MWh in the EBE scenario. The utilization level of wind energy is reduced by about 11% when EBE occurs. In addition, EBE hurts the expected net profit of WPPs. If EBE occurs, the WPPs' net profit drops about 20%, from approximately $16,000 to $13,000. Therefore, I conclude that the FTR policy limits the effect of replacing fossil-fuel generators by integrating wind power. In particular, if the generators for a base-load supply such as G_1 have a high-pollutant intensity, the ability of using wind power to reduce emission will be much weaker than expected when EBE occurs. For example, in my numerical simulation, to balance the same amount of demand, the EBE increases CO_2 emissions by 8.9%, SO_2 emissions by 26.2% and NO_x emissions by 13.1%.

Even ignoring the cost of potential environmental damage, EBE leads to a higher expected generation cost. In my numerical experiment, the total expected generation cost to balance a 1500 MWh demand is $36,073. When EBE occurs, the generation cost increases to $36,400, about 0.9% higher than the former situation. As I assume the demand is constant in the numerical experiment, the FTR policy reduces the total expected social surplus and leads to a deadweight loss in the market when EBE occurs.

Furthermore, under the expected social-welfare maximization framework, the EBE can reduce the consumers' payments for the same amount of electricity. In my numerical experiment, when EBE does not occur, the consumers' payment for 1500 MWh is approximate $53,920. Thus, the EBE decreases the consumers' payment by 8.4% to $49,392.

5.4. When FTR holders have market power and can impact the congestion probability

If G_1 has market power, it has incentive to reduce generation commitment to increase the market price. Consequently, EBE is weaker than when G_1 does not have market. When G_1 can manipulate the price, the optimal $q_1 < K$ must satisfy the following condition:

$$c_1\prime(q_1) = p_1^a + q_1 \frac{dp_1^a}{dq_1} + \alpha_1 \theta. \tag{17}$$

Because the G_1' RID curve is downward as shown in Fig. (3), I have $dp_1/dq_1 \leq 0$. Thus, G_1 will produce less than when it does not have market power.

Table 1: Market Conditions with Different Market Structures

	Market Scenario		
	No EBE	EBE and Competitive Market	EBE and Market Power
	The DA Market Outcomes		
LMP of Node 1 ($/MWh)	16	7	13.8
G_1's Generation (MWh)	253.3	321.5	267.9
Expectation of Entitlements of FTRs ($)	11392.0	13415.9	12055
Expectation of G_1's Net Profit ($)	11392.0	10522.7	11465.7
	Expectation of Outcomes of the DA Market		
Wind Power Generation (MWh)	446.2	397.1	437.0
	(50.3)	(76.3)	(51.8)
Net Profit of WPP ($)	15967.0	12901.1	15281.2
	(2666.9)	(1763.1)	(2496.2)
G_2's Generation(MWh)	800.5	781.4	795.1
	(50.3)	(76.3)	(51.8)
G_2's Net Profit($)	32019.9	31256.9	31803.5
	(2010.8)	(3052.9)	(2071.5)
	Expectation of Outcomes of the Whole Market		
Consumers' Expenditure($)	53920.0	49391.9	52981.4
Total Generation Costs($)	36073.3	36400.2	36089.6
CO_2 Emissions (metric ton)	3259.1	3549.1	3317.7
	(125.8)	(191.0)	(129.6)
SO_2 Emissions (metric ton)	7.4	9.4	7.9
	(0.4)	(0.7)	(0.5)
NO_x Emissions (metric ton)	6.4	7.2	6.5
	(0.2)	(0.3)	(0.2)

In Fig. 3, I demonstrate that EBE is weaker than it is when G_1 has no market power. When G_1 has market power, its bidding curve is shown as the blue curve. The market-power LMP of Node 1 is P_{MP-EBE}, which is higher than P_{PT-EBE}, but still lower than P_{noEBE}. Correspondingly, G_1's commitment level $Q_{1MP-EBE}$ is lower than $Q_{1PT-EBE}$, but higher Q_{1noEBE}.

In Column 3 of Table 1, I summarize the market outputs when G_1 is a market power. In this scenario, the net profit of G_1 achieves the highest level and the EBE is weaker than it is when G_1 has no market power. Consequently, the utilization level of wind power is higher. At the same time, the emissions from the electricity generation are lower than those when G_1 is has no market power. Interestingly, when the EBE occurs, the social welfare when G_1 is a market power is higher than when G_1 has no market power.

6. Counter-Factual Policy Scenarios

Because the functional forms in my model setting are general, my framework can be used to analyze the effects of some broadly discussed policies, such as the RT-retail price and the carbon tax. In this section, I analyze the impacts of these policies if EBE occurs.

6.1. RT retail price and elastic demand

If the demand is elastic, by using Theorem 3.2 I can deduce the following corollary:

Corollary 6.1. *If the aggregate demand curve is strictly decreased and the marginal cost function of G_2 is strictly increased, a higher commitment level of the DA market induces a higher consumption level and a lower generation level of G_2.*

Proof. Let Q represent the total consumption level, then

$$Q = \min\{q_1 + W, K\} + q_2. \tag{18}$$

Then, G_2's generation q_2 is

$$q_2 = Q - \min\{q_1 + W, K\}. \tag{19}$$

At the same time, according to the market clearing condition in the RT market $p(Q) = c_2\prime(q_2)$, I can deduce $q_2 = c_2\prime^{-1}(p(Q))$; thus, I have

$$Q - c_2\prime^{-1}(p(Q)) = \min\{q_1 + W, K\}. \tag{20}$$

Because the inverse demand curve is strictly decreasing and $c_2^{-1}\prime(q_2)$ is strictly increasing, the left-hand side of Eq.(20) is a non-decreasing function of Q. At the same time, a higher q_1 results in a higher value of $\min\{q_1 + W, K\}$, which is the right-hand side of Eq.(20). Therefore, a higher DA commitment level q_1 corresponds to a higher total consumption level Q for any given level of wind power W. Hence, a higher DA commitment level q_1 corresponds to a higher expected total consumption level $E[Q]$.

Since $c_2\prime^{-1}(q_2)$ is strictly increasing, a higher Q induces a lower q_2 because a higher Q indicates a lower LMP in Node 2 in the RT market. □

The economic explanation for Corollary (6.1) is as follows. Holding some FTRs subsidizes G_1's commitment, resulting in a reduction in the marginal cost of importing power in the DA market. Hence, the total expected power import is increased (shown as the left-hand side of Eq. (20)). Furthermore, in the RT market, the ISO could buy less from G_2 to balance the demand, which would result in a lower LMP in Node 2. As a rebound effect, the lower LMP in Node 2 gives the consumers an incentive to use more electricity. Because EBE induces a higher total consumption level, the emissions are higher in a elastic-demand scenario than it is in an inelastic-demand scenario.

6.2. Carbon Tax

Introducing a carbon tax into the market changes the relative price ratio of q_1 and q_2. To intuitively present the impacts of a carbon tax, I assume the marginal cost of G_1 is c_1 and the marginal cost of G_2 is c_2. I use τ_c to represent the carbon tax rate and e_i to denote the emission rate of G_i. If the wind power is distributed as a normal distribution $N(\bar{w}, \sigma^2)$, the DA-commitment level with G_1 after introducing the carbon tax is

$$q_{1c} = K - \bar{w} - \Phi^{-1}\left(\frac{c_1 + e_1\tau_c}{c_2 + e_2\tau_c}\right). \tag{21}$$

When the carbon tax is not implemented, the DA-commitment level $q_1 = q_{1c}(\tau_c = 0)$. Here, the function $\Phi(x)$ is the cumulative probability function of the standard normal distribution.

If the WPPs are allowed to participate only in the RT market and the SO makes the DA-generation plan according to the dispatch strategy in Section 4, a carbon tax can increase the risks to holders of FTRs if G_1 is more carbon intensive than G_2. Compared with q_1, $q_{1c}(\tau_c = 0)$ will be lower if $e_1 \geq e_2$, and vice versa. Therefore, if G_1 is a more carbon-intensive generation portfolio than G_2, the ratio $\frac{c_1+e_1\tau_c}{c_2+e_2\tau_c}$ will increase after introducing a carbon tax into the market and the DA-commitment level with G_1 drops. As a result, the holders of FTRs face even higher risks than in a scenario without a carbon tax.

The impacts of a carbon tax on EBE produce is complicate. I check two simple scenarios. By recalling Definition (6), if G_2's generation can lead to carbon emissions, introducing a carbon tax into the market can push the inverse demand curve to G_1 upwards. If G_1's generation is carbon free, the EBE will be aggravated, and the utilization level of wind power will be more heavily discouraged.

In contrast, if G_2's generation is carbon free and G_1's generation results in carbon emissions, the inverse demand curve to G_1 does not change, but G_1's bidding curve will shift downwards in Fig. 3. If G_1's bidding curve in the EBE situation is linear, a carbon tax can mitigate the increase of G_1 's commitment, which is caused by the EBE. If both G_1 and G_2 emit green house gas during electricity generation, the effects of a carbon tax on EBE would need to be discussed on a case-by-case basis.

7. Conclusion

I have demonstrated that integrating wind power into an electricity market with transmission congestions creates a situation in which market operators face either overconsumption of electricity or the failure of the FTR policy. In a completely competitive market, both the two effects will lead the market equilibrium to deviate from the social optimum.

In many electricity markets, WPPs are defined as RC and need to make generation commitment in the DA market. In this scenario, consumers do not respond to the unexpected shortfall in the RT market. Consequently, they consume too much electricity.

However, if WPPs are not defined as RC, the risk of loosing all FTR entitlement will stimulate FTR holders to strategically bid in the electricity market. Consequently, the distribution of the FTRs is connected with electricity-market equilibrium. In order to gain a high expected FTR entitlement, a GenCo holding FTRs will bid, even if the market price is lower than its marginal costs. More FTRs held by a conventional GenCo can encourage the GenCo to commit more with the same price in the DA market. Consequently, the total consumption level is higher than the socially optimal level too.

If the real-time residential price, the dead weight losses are even higher than when the residential price is flat. The effects of the carbon tax is complicate and need to be examine case by case.

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Appendix A. Proofs of Theorems

A1.Proof of Theorem 3.2

Proof. I assume $p(K) > c_1\prime(K)$. Without wind, the SO schedules K MW from Node 1 in the DA market. If there is wind power in the market, the SO schedules less because wind power might lead to lower price in the RT market.

In DA market, G_1's net profit problem is shown as Problem (2), from the first order condition of this problem, I can directly obtain the Eq. (3).

The SO need to determine how much to commit with each generation company. If the SO schedules $q_1 = K$ with G_1, the transmission line will be congested by the committed generation from G_1 and no wind power will be utilized. As a result, the market equilibrium is the solution of a deterministic optimal power flow; then the SO is indifferent to commitment with G_2 in the-day ahead market or in the RT market.

As the marginal cost of WPPs are 0, their generation level in the RT market will be $\min\{K - q_1, W\}$ since my model does not allow negative load and negative LMP; therefore, the KKT conditions of Problem 4 are:

$$\frac{\partial E[u_d]}{\partial q_1} = E[u\prime(q_2^a + q_2^r + W + q_1)\mathbf{1}(W + q_1 < K) + p_2^r\mathbf{1}(W + q_1 \geq K)] - p_2^a \qquad = 0, \tag{A.1}$$

$$\frac{\partial E[u_d]}{\partial q_2^r} = E[(u\prime(q_2^a + q_2^r + W + q_1) - p_2^r)] = 0, \tag{A.2}$$

$$\frac{\partial E[u_d]}{\partial q_2^a} = E[(u\prime(q_2^a + q_2^r + W + q_1) - p_2^a)] = 0, \tag{A.3}$$

$$q_1 \leq K, \tag{A.4}$$

$$p_2^a = c_2\prime(q_2^a), \tag{A.5}$$

$$p_2^r = c_2\prime(q_2^a + q_2^r), \tag{A.6}$$

$$\lambda \cdot (q_1 - K) = 0. \tag{A.7}$$

I use λ to denote the the shadow price of the transmission line constrain in the DA market $q_1 \leq K$.

In the RT market, market equilibrium q_2 should always satisfy $u_d\prime(q_2+\min\{W+q_1, K\})-p_2^r = 0$ for any q_1. Because this equation is valid when $W + q_1 < K$, I have $E[u\prime(q_2 + W + q_1)\mathbf{1}(W + q_1 < K)] = E[p_2^r\mathbf{1}(W + q_1 < K)]$; substitute $u\prime(q_2 + W + q_1)$ by p_2^r, I can get $p_2^a = E[p_2^r]$. From the market clearing condition and definition of LMPs, I have $p_1^a + \lambda = p_2^a = E[p_2^r]$ that is Eq. (5). □

Proof of theorem 5.2

Proof. The commitment level of q_1 satisfies Eq. ((3)), q_1 is a function of α_1 when $q_1 < K$.

Moreover

$$\frac{\partial^2 u_1}{\partial q_1 \partial \alpha_1} = K\frac{\partial E[(p_2 - p_1)\mathbf{1}(q_1 + w > K)]}{\partial q_1} \geq 0. \tag{A.8}$$

Therefore, the larger the fraction α_1, the stronger the effect of encouraging G_1 bidding more. □

Appendix B. A three-node loop scenario

The two-node case helps us understand the impacts of the integration of wind power on the FTR holders' entailments in a radial network(Rajagopal et al., 2014). Power-market analysis for a loop network is a more complicated question. In a loop system, the power flow follows Kirchhoff's

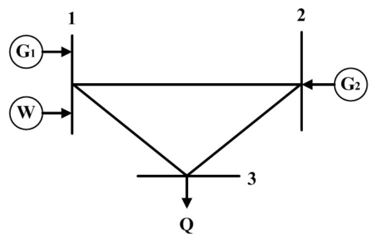

Figure B.4: A Three-Node Loop Case

laws, and the distribution of the power flows is determined by the impedances of each link and the injected/withdrawn power at every node. Because the pattern of the power flow in a loop system is different from a radial system, a conclusion derived from the radial network does not necessarily carry over in a loop system. Following the literature, I use the three-node loop model shown in Fig. (B.4) to analyze how the FTR affects the power-market equilibrium in a loop network(Joskow and Tirole, 2000)(Oren et al., 1995).

Appendix B.1. Model Setup

I assume that all three grids have the same impedance; Node 1 and Node 2 are linked by line L_{12}, which has transmission limit K, while the other two transmission lines have sufficient capacity. As shown in Fig. (B.4), G_1 and WPPs are located at Node 1, G_2 is in Node 2, and consumers are located at Node 3. I assume that the characteristics of the GenCos and the consumers are similar to the two-node scenario.

Similar to the two-node scenario, p_i^a is the DA LMP of node i and q_i^a is the DA committed amount of electricity from G_i. I do not include the transmission losses in my analysis, therefore I have $p_1^r = p_2^r = p_3^r$ when the transmission line is not congested.

Because the three grids have the same impedance, following a simple power-flow analysis, the market equilibrium of the DA market will lead to a virtual power flow in L_{12} with the scheduled amount

$$f_{12}^a = \frac{q_1^a - q_2^a}{3}. \tag{B.1}$$

The flow must respect the transmission limit, thus must be less than K.

In the RT market, consumers purchase electricity from WPPs in Node 1 and G_2 in Node 2. I denote the RT LMP of Node i by p_i^r. Similarly, only G_2 can generate more than its DA commitment and $q_2 = q_2^a + q_2^r$. Then, the power purchased from all GenCos will lead to a power flow in line L_{12} with amount

$$f_{12}^r = \frac{q_1 + W - q_2}{3}. \tag{B.2}$$

The power flow f_{12}^r must less than K.

Appendix B.2. Optimal dispatch in the loop scenario

In order to focus on the congestion scenario, I assume that $c_2\prime(0) > c_1\prime(3K)$, thus line L_{12} will be congested when the penetration of wind power is zero. Therefore, if wind generation W is deterministic and large enough, line L_{12} will be congested because zero-cost wind energy further reduces the generation costs at Node 1. Most definitions and analyses follow Section 3, but I also need to consider the loop-flow constraints

In the DA market, the SO's optimal dispatch problem is similar to Problem (4). Only the transmission constraints are changed to

$$(q_1 - q_2^a)/3 \leq K, \tag{B.3}$$

$$(q_1 - q_2^a)/3 \geq -K. \tag{B.4}$$

If the transmission line L_{12} is congested in the direction from Node 1 to Node 2, I use η^a/η^r to represent its shadow price in the DA/RT market. If the line is congested in the opposite direction, I use ζ^a $/\zeta^r$ to represent the shadow price in the DA/RT market. Then, the expected FTR entitlement is

$$\Theta = \eta^a + \eta^r E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)]. \tag{B.5}$$

In Theorem Appendix B.1, I express the conditions that should be satisfied by the optimal bidding strategies of G_i in the DA market.

Theorem Appendix B.1. *Given the distribution of W, the optimal bidding strategy of G_1 and G_2 in the DA market in the three-node loop system is expressed as follows:*

$$c_1\prime(q_1) = E[u_d\prime] + (-\eta^a + \zeta^a)/3 + K\alpha_1 \frac{\partial \Theta}{\partial q_1}, \tag{B.6}$$

$$c_2\prime(q_2^a) = E[u_d\prime] + (\eta^a - \zeta^a)/3 + K\alpha_2 \frac{\partial \Theta}{\partial q_2^a}. \tag{B.7}$$

In particular, I have $\eta^a \cdot \zeta^a = 0$ and $\eta^r \cdot \zeta^r = 0$, as congestion only occurs in one direction.

Proof. In the DA market, G_1 decides its committed generation to maximize their net profits. If G_1 holds α_1 proportion of FTRs, its net-profit maximization problem is shown as follow:

$$\max_{q_1} p_1^a q_1 - c_1(q_1^a) + \alpha_1 K(E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)] + \eta^a + \zeta^a). \tag{B.8}$$

Similarly, G_2's net profit maximization problem is expressed as follow:

$$\max_{q_2^a} p_2^a q_2^a - c_2(q_2^a) + \alpha_2 K(E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)] + \eta^a + \zeta^a). \tag{B.9}$$

According to the consumers' aggregate utility function and G_1's bidding curve, the SO's DA dispatch maximizes the expected total social net profit that is equivalent to:

$$\begin{aligned}
\max_{q_1} \; & E[u(q_2^a + q_2^r + \min\{W + q_1, K\}) - c_1(q_1) - c_2(q_2^a + q_2^r)] \\
& + \alpha_1(p_{12}^a(p_2^a - p_1^a) + E[(p_{12}^r - p_{12}^a)(p_2^r - p_1^r)\mathbf{1}(p_{12}^r \geq K))] \\
\text{s.t.:} \; & (q_1 - q_2^a)/3 \leq K \\
& (q_1 - q_2^a)/3 \geq -K.
\end{aligned} \tag{B.10}$$

The market equilibrium conditions for the DA market described by Eqs. (B.10), (B.8) and (B.9) are:

$$c_1\prime(q_1) = p_1^a + K\alpha_1 \frac{\partial E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)]}{\partial q_1}, \tag{B.11}$$

$$c_2\prime(q_2^a) = p_2^a + K\alpha_2 \frac{\partial E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)]}{\partial q_2^a}, \tag{B.12}$$

$$E[u_d\prime] - p_3^a = 0, \tag{B.13}$$

$$p_2^a = p_3^a + (\eta^a - \zeta^a)/3, \tag{B.14}$$

$$p_1^a = p_3^a + (-\eta^a + \zeta^a)/3. \tag{B.15}$$

From above conditions, I can easily derive Conditions (B.6) and (B.7).

□

In the real-time market, the transmission constraints of the SO's optimal dispatch problem are:

$$\frac{q_1 + w - q_2^a - q_2^r}{3} \leq K, \tag{B.16}$$

$$\frac{q_1 + w - q_2^a - q_2^r}{3} \geq -K. \tag{B.17}$$

Then, the market equilibrium conditions are:

$$p_2^r = c_2\prime(q_2) = c_2\prime(q_2^a + q_2^r), \tag{B.18}$$

$$p_2^r = p_3^r + \frac{\eta^r - \zeta^r}{3}, \tag{B.19}$$

$$p_3^r = u_d\prime(q_1 + q_2 + w), \tag{B.20}$$

$$p_1^r = p_3^r - \frac{-\eta^r + \zeta^r}{3} - \rho. \tag{B.21}$$

Here, ρ is the shadow value of constraint $w \leq W$. I derived these conditions following (Joskow and Tirole, 2000).

Appendix B.3. Market failure when the WPPs are defined as RC

Here, all model setups and analyses are the same as in Section 4 except that the DA-transmission constraint here is:

$$(q_1 + \bar{w} - q_2^a)/3 \leq K, \tag{B.22}$$

$$(q_1 + \bar{w} - q_2^a)/3 \geq -K. \tag{B.23}$$

DA Market. In Theorem Appendix B.2, I express the conditions that should be satisfied by the market equilibriums of the DA market. The proof is included in the Appendix.

Theorem Appendix B.2. *Given the distribution of W, the market equilibrium of the DA market in the three-node loop system satisfies Eq. B.6 and Eq. B.7 and the following condition:*

$$\frac{\partial E[p_2^r(\bar{w} - W)\mathbf{1}(W \leq \bar{w})]}{\partial \bar{w}} = E[u_{d'} + (-\eta^a + \zeta^a)/3 + K\alpha_w \frac{\partial \Theta}{\partial \bar{w}}. \tag{B.24}$$

In particular, I have $\eta^a \cdot \zeta^a = 0$ and $\eta^r \cdot \zeta^r = 0$ because the congestion will only occur in one direction.

RT Market. All of the analyses are the same as in Section 4. If wind power W is larger than $\bar{w}$, there would be no trade in the RT market. On the other hand, if the wind power W is less than $\bar{w}$, the WPPs must either purchase electricity from G_2. Therefore, the total consumption will be larger than the socially optimal level.

The FTR entitlement. In the loop example, the line will be congested in the DA market no matter how much $\bar{w}$ is committed. Therefore, the FTR holders can be fully funded by the pro-rata entitlement in the DA market. If the W is large enough to guarantee the RT commitment to satisfy condition $u_{d'}(q_1 + q_2 + w) \geq c_{2'}(q_2)$, wind-power integration will have no impact on the FTR holders' entitlement. However, if the W is too low in the RT market and causes the RT commitment to satisfy the condition that $u_{d'}(q_1 + q_2 + w) < c_{2'}(q_2^a + q_2^r)$, the holders of FTRs would pay the congestion charges if the congestion occurs from Node 2 to Node 1. To avoid the EBE risk, the SOs can defined FTRs as options.

Appendix B.4. The failure of the FTR policy when the WPPs are not defined as RC

When the WPPs are not defined as RC, I have the following corollary.

Corollary Appendix B.3. *In the three-node loop system, if the WPPs are not defined as RC, even if the transmission line is expected to be congested, the FTR holders might lose their entitlements when the wind power is less than the predicted amount in the DA market. In some extreme situations, the FTR holders need to pay for the congestion that occurs in the contrary directions.*

Proof. From Eqs. (B.6) and (B.18)-(B.20), if the DA commitments from G_1 and G_2 satisfy

$$E[c_2\prime(q_2^a + q_2^r) - \frac{\eta^r - \zeta^r}{3}] > c_1\prime(q_1) - K\alpha_1 \frac{\partial \Theta}{\partial q_1}, \tag{B.25}$$

Proof. The KKT conditions of the market equilibrium are:

$$\underbrace{p_1^a}_{\text{A}} + \underbrace{K\alpha_w \frac{(E[(\eta^r - \zeta^r)\mathbf{1}(W \le \bar{w})]]}{\partial \bar{w}}}_{\text{B}} = \underbrace{E[p_2^r \mathbf{1}(W \le \bar{w})]}_{\text{C}}, \tag{B.26}$$

$$c_1\prime(q_1) = p_1^a + K\alpha_1 \frac{\partial E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)]}{\partial q_1}, \tag{B.27}$$

$$c_2\prime(q_2) = p_2^a + K\alpha_2 \frac{\partial E[(\eta^r + \zeta^r)\mathbf{1}(W + q_1 - q_2^a - q_2^r > 3K)]}{\partial q_1}, \tag{B.28}$$

$$E[u_d\prime] - p_3^a = 0, \tag{B.29}$$

$$p_2^a = p_3^a + (\eta^a - \zeta^a)/3, \tag{B.30}$$

$$p_1^a = p_3^a + (-\eta^a + \zeta^a)/3. \tag{B.31}$$

From above equations, I can easily derive Condition B.24.

□

the DA dispatch will result in the line congestion. The FTR holders will receive the pro rata entitlement from the DA congestion charges. The total entitlements are η^a.

Otherwise, if the DA commitments from G_1 and G_2 satisfy the condition

$$E[c_2\prime(q_2^a + q_2^r) - \frac{\eta^r - \zeta^r}{3}] = c_1\prime(q_1) - K\alpha_1 \frac{\partial \Theta}{\partial q_1}, \tag{B.32}$$

then the DA market equilibrium will not lead to transmission congestion after integrating the wind power into the grid, and the FTR holders will not receive entitlements in the DA market.

In the RT market, if $u_d\prime(q_1+q_2+w) > c_2\prime(q_2)$, the equilibrium conditions shown as Eqs. (B.18)-(B.20) indicate that the wind energy W is large enough to congest the line L_{12}, and the FTR holders will be paid by pro rata entitlements.

If the equilibrium in the RT market satisfies $u_d\prime(q_1 + q_2 + w) = c_2\prime(q_2)$, I can conclude that W is not sufficiently large and the line L_{12} is not congested; here, the FTR entitlements are zero.

Furthermore, if the equilibrium in the RT market satisfies $u_d\prime(q_1 + q_2 + w) < c_2\prime(q_2)$, indicating that the wind power is very small and the aggregate demand is relatively high, the transmission congestion will occur in the direction from Node 2 to Node 1, and the FTR holders would be required to pay for the congestion charges if the FTRs are defined as obligations; on the other hand, the FTR holders would not need to pay for the congestion and would not receive entitlement if the FTRs are defined as options. □

From the above proof process, I can conclude that integrating wind energy under the current protocol will bring new risks to the holders of FTRs in the loop scenario.

From Eq.(B.6), I can still conclude that the EBE might occur when G_1 is given some FTRs. The reason is similar to that in Section 5.2 for the two-node case. Consequently, the EBE results in a higher commitment level of G_1 and a lower market-clearing price in the DA market.