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Measuring the competitiveness benefits of a transmission investment policy: The case of the Alberta electricity market

Frank A. Wolak

Department of Economics, Stanford University, Stanford, CA 94305-6072, USA

HIGHLIGHTS

- Define competitiveness benefits to consumers from transmission expansions in wholesale market.
- Compute upper and lower bounds on competitiveness benefits for Alberta market.
- Compare no-perceived congestion prices to actual prices to measure competitiveness benefits.
- Economically substantial competitiveness benefits found for sample period studied.
- To ensure adequate transmission, planning processes should account for these benefits.

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ABSTRACT

Transmission expansions can increase the extent of competition faced by wholesale electricity suppliers with the ability to exercise unilateral market power. This can cause them to submit offer curves closer to their marginal cost curves, which sets market-clearing prices closer to competitive benchmark price levels. These lower wholesale market-clearing prices are the competitiveness benefit consumers realize from the transmission expansion. This paper quantifies empirically the competitiveness benefits of a transmission expansion policy that causes strategic suppliers to expect no transmission congestion. Using hourly generation-unit level offer, output, market-clearing price and congestion data from the Alberta wholesale electricity market from January 1, 2009 to July 31, 2013, an upper and lower bound on the hourly consumer competitiveness benefits of this transmission policy is computed. Both of these competitiveness benefits measures are economically significant, which argues for including them in transmission planning processes for wholesale electricity markets to ensure that all transmission expansions with positive net benefits to electricity consumers are undertaken.

1. Introduction

The transition from a price-regulated, vertically-integrated monopoly regime to the wholesale market regime in the electricity supply industry has dramatically altered the role of the transmission network. Under the vertically-integrated monopoly regime, the electric utility had a requirement to serve all demand in its service territory at the regulated price. This mandate provided a strong incentive for the utility to operate its existing generation units in a least-cost manner given the configuration of its transmission network and the geographic location of the daily electricity demand served, and to make investments in additional transmission capacity when this was the least-cost approach to supply load growth in a given geographic area.

In contrast, under the wholesale market regime the owner of the transmission network is financially independent of any generation unit owner and receives a regulated revenue stream that is independent of the level of congestion in the transmission network. An owner of multiple generation units selling into a wholesale market can find it expected profit-maximizing to exploit the configuration of the transmission network to cause transmission congestion and shrink the size of the geographic market over which its units face competition in order to increase the revenues it receives from participating in the wholesale

E-mail address: wolak@zia.stanford.edu

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market.[1]

For these two reasons, the transmission network takes on a new role in the wholesale market regime as facilitator of competition. Therefore, the configuration of the transmission network determines the extent of competition that each supplier faces for a given geographic distribution of electricity demands. Transmission expansions can increase the number of hours of the year that a supplier faces sufficient competition to cause it to submit offer curves close to its marginal cost curve and thereby yield lower market-clearing prices.

The competitiveness consumer benefit of a transmission expansion is the reduction in wholesale revenues – the amount consumers pay for wholesale electricity – as a result of the transmission expansion causing more competitive offer behavior by wholesale suppliers. This occurs because the upgrade allows more generation unit owners to compete to supply electricity at potentially every location in transmission network.[2] In the former vertically-integrated monopoly regime, the standard measure of the economic benefits of a transmission expansion was the reduction in the total cost of the vertically-integrated firm serving system-wide demand as a result of the upgrade. There are also likely to be production cost reductions associated with reducing the incidence of transmission congestion because lower cost generation units can operate more frequently. Because the transmission network in the wholesale market regime is financially separate from the generation segment of the industry and generation unit owners can take actions to profit from the configuration of the transmission network at the expense of electricity consumers, if the annual consumer benefits associated with an upgrade are greater than the annual fixed and variable cost of the expansion, consumers collectively should be willing to pay for this upgrade.[3]

This paper presents an empirical approach that quantifies the magnitude of the competitiveness benefits from a hypothetical transmission expansion for a wholesale electricity market. Upper and lower bound estimates are computed for the change in hourly market prices and wholesale energy costs to consumers in the Alberta Wholesale Electricity Market (AWEM) that result from increasing the extent of competition that the five largest suppliers in the market face because of an expected reduction in the frequency and duration of transmission constraints. These counterfactual market outcomes also yield upper and lower bounds on the production cost saving associated with reducing the frequency and duration of transmission congestion. Both counterfactuals yield economically significant competitiveness benefits to electricity consumers from a transmission policy that causes the five largest suppliers to perceive a low frequency and duration of transmission constraints. These results imply that failing to account for this source of consumer benefits in the transmission expansion planning process for regions with formal wholesale electricity markets can leave transmission expansions with positive net benefits to electricity consumers on the drawing board.[4]

The approach used to assess the competitiveness benefits of transmission expansions builds on the models of expected profit-maximizing offer behavior described in Wolak (2000, 2003, 2007), where suppliers submit hourly offer curves into the short-term market to maximize their expected profits from selling energy given the distribution of residual demand curves they face. As shown in Wolak (2000), this residual demand curve distribution determines the extent of competition that a supplier faces, and therefore how close the supplier's offer curve is to its marginal cost curve. Transmission expansions typically reduce the slope of the realized residual demand curves that a supplier faces because more offers from other locations in the transmission network are not prevented from competing with that supplier because of transmission constraints. These flatter residual demand curves cause an expected profit-maximizing supplier to submit an offer curve closer to its marginal cost curve. If all strategic suppliers face flatter residual demand curve realizations because of increased transmission capacity, then they will find it expected profit-maximizing to submit offer curves closer to their marginal cost curve which will yield market-clearing prices closer to competitive benchmark levels.

The major challenge associated with computing these counterfactual offer curves for each strategic supplier is quantifying how the curves will change in response to each supplier facing a flatter residual demand curve distribution because of the transmission expansions. The approach used here is based on the framework implemented by McRae and Wolak (2014) to determine how much a supplier's offer curve into the hourly short-term market changes in response to changes in the residual demand curve that it faces that hour. An econometric model relating the hourly offer price submitted by a supplier to the hourly inverse semi-elasticity of the residual demand curve (defined in McRae and Wolak, 2014) faced by that supplier is estimated for each of the five large suppliers in the AWEM using the hourly offer curves submitted by all market participants over the period January 1, 2009–July 31, 2013.[5] For each of the five of the largest suppliers, the model estimated yields an increasing relationship between the supplier's hourly offer prices and the hourly inverse semi-elasticity it faces.

This estimated relationship between the hourly offer price and hourly inverse semi-elasticity for each market participant is used to compute a counterfactual offer curve for each supplier that is the result of the perceived increased competition that the strategic supplier would face as a result of increased transmission capacity. This is accomplished through the following process. First, a no-congestion residual demand curve is computed for each hour for each supplier using the offer curves actually submitted by all

[1] Borenstein et al. (2000) use a two-node model of quantity-setting competition between two suppliers separated by finite-capacity transmission line serving price-responsive demands at both nodes to show that limited transmission capacity between the two locations gives each firm an additional incentive to restrict its output in order to congest the transmission line and reduce the competition it faces in its local market in order to raise the price it receives for its output. The authors also demonstrate that relatively small investments in transmission capacity can yield significant increases in the competitiveness of realized market outcomes. Arellano and Serra (2008) extend this result to the case of a cost-based short-term market similar to the ones that exist in a number of Latin American countries. The amount of transmission capacity between the two regions impacts the mix of high fixed-cost and low variable cost base load capacity and low fixed-cost and high variable cost peaking capacity suppliers choose, with additional transmission capacity causing suppliers at both locations to choose a capacity mix closer to the socially efficient level.

[2] This change in supplier behavior pre- and post-hypothetical transmission upgrade should account any market power mitigation mechanisms that impact supplier behavior in the short-term market.

[3] Although competitiveness benefits are primarily a transfer from electricity generation unit owners to electricity consumers, to the extent wholesale prices are lower because of the transmission expansion, retail electricity demand may be higher if the lower wholesale prices are passed on into lower retail prices. In addition, there may be system-wide operating cost savings from the transmission upgrade because more lower marginal cost units are able to serve demand. Consequently, there are also potential consumer surplus and producer surplus gains as a result of the upgrade.

[4] Awad et al. (2010) estimate the economic benefits associated with the Palo Verde-Devers Number 2 transmission line expansion in Southern California and find that the competitiveness benefits associated with this upgrade are a significant source of the economic benefits to electricity consumers and the upgrade would be more likely to fail the economic benefits versus cost test without them.

[5] The hourly generation unit-level offer curves submitted by each of the five largest suppliers in the market are used to compute each supplier's hourly offer price and the hourly market demand and aggregate offer curves of all other market participants are used to construct the hourly residual demand curve facing each large supplier.

suppliers, assuming that the offer curves of all other suppliers, even the portions of the offer curves that were impacted by transmission constraints, can compete against the offers of the firm under consideration. Second, the inverse semi-elasticity of this hourly no-congestion residual demand curve is computed and the coefficient estimate from the regression of the hourly offer price for that supplier on the hourly inverse semi-elasticity it faced is used to compute a counterfactual Canadian Dollar (CAD) per Megawatt-hour (MWh) reduction in the hourly offer price. This counterfactual offer price is lower than the actual offer price because the no-perceived-congestion hourly inverse semi-elasticity is smaller than the actual inverse semi-elasticity which reflects the presence of transmission constraints. The estimated relationship between the supplier's offer price and the inverse semi-elasticity of the residual demand curve it faces implies a lower counterfactual hourly offer price if the supplier faces a no-congestion residual demand curve. This estimated CAD/MWh reduction in the supplier's offer price is applied to all hourly offer prices for all quantity increments on that supplier's offer curve.

The final step of the process uses these counterfactual offer curves for the five largest suppliers in the market and the actual offer curves of the remaining suppliers to compute an aggregate counterfactual offer curve. The counterfactual hourly market price that reflects the competitiveness benefits of no expected transmission congestion is computed by crossing the resulting aggregate offer curve with the actual demand for that hour. This procedure is repeated for all hours in the sample period.

This process is repeated in two ways in order to compute an upper and lower bound on the level of the counterfactual price that results from no expected transmission congestion by the five large strategic suppliers.[6] To compute a lower bound on the counterfactual no-congestion price (which is used to compute an upper bound on the consumer benefits from transmission expansions), the counterfactual aggregate supply curve is computed using the adjusted offer curves for the five largest firms and actual offer curves for all other firms. The price at the intersection of this curve with the aggregate demand curve yields a lower bound on the counterfactual no-congestion price, because it assumes that there is sufficient transmission capacity so that all of the offers on the aggregate offer curve below this counterfactual price can be accepted to supply energy.

To compute an upper bound on the counterfactual no-congestion price (which is used to compute a lower bound on the consumer benefits from transmission expansions), the counterfactual aggregate supply curve is constructed using only quantity steps on the individual supplier-level offer curves that were actually accepted to provide energy. This implies that the counterfactual price is equal to the highest offer price with a positive quantity accepted from it in the actual hourly dispatch process. This second approach provides an extremely conservative estimate of the counterfactual market price with no perceived transmission congestion because it assumes exactly the same output quantity for all generation units in the system and same amount and location of transmission constraints as actually occurred. More competitive behavior by strategic suppliers, even with same amount of transmission capacity, is likely to allow some generation capacity now offered at a lower price to sell energy and set a lower market-clearing price, which is why this approach yields a slack upper bound on the counterfactual no-congestion price.

Both of these counterfactual prices yield economically significant competitiveness benefits from transmission expansions that decrease the inverse semi-elasticity of the residual demand curves that the five largest suppliers face. The sample average hourly consumer benefit using the upper bound on the counterfactual no-perceived-congestion price is 2689 CAD. However, this average hourly value varies considerably over the fifty-five months of the sample. During one month it exceeds 12,500 CAD. The sample average hourly consumer benefit using the lower bound on the counterfactual no-perceived-congestion price is 77,857 CAD. This magnitude also varies over months of the sample, taking on a value greater than 400,000 CAD for one month.

Translating these two consumer benefit measures from the perceived elimination of transmission constraints into percentages of the total wholesale market revenues implies a lower bound on the consumer benefits for the entire sample of 0.48% of total wholesale market revenues, with this percentage reaching as high as 1.6% of total wholesale marketrevenues in one month of the sample. For the entire sample, the upper bound on the consumer benefits is 14% of total wholesale market revenues. During a number of months, this percentage is substantially higher. For example, it is more than 36% of actual wholesale market revenues in one month. For most of the months this percentage is below 20%, but it never falls below 5%.

The remainder of this paper proceeds as follows. The next section describes the basic features of the AWEM and the process used to set market-clearing prices given the offers submitted to Alberta Electric System Operator (AESO). This section also presents summary statistics on the market structure and market outcomes in the AWEM. Section 3 describes the details of how the two counterfactual no-predicted-congestion prices are computed. Section 4 presents the results of these computations. Section 5 discusses the implications of these results for the design of transmission planning processes in organized wholesale electricity markets.

2. The Alberta wholesale electricity market

The AESO was formed in 2003 as a non-profit entity that is independent of all industry participants and owns no transmission or generation assets. In 2013 it had approximately 175 participants and processed close to $8 billion in electricity-related transactions. The AESO operates an hourly real-time energy market using a single-zone pricing model where one province-wide price of energy is set for each of hour of the day. Ancillary services are procured and dispatched to maintain adequate operating reserves throughout the day by the AESO through an independent third-party market and over-the-counter transactions.

As shown in Table 1, thermal generation accounts for most of Alberta's installed capacity. Coal-fired generation accounts for slightly more than 46% of the province's installed capacity. Natural gas-fired cogeneration is 27%, and natural gas-fired combined-cycle generation and natural gas-fired combustion turbine together account for approximately 12% of the installed capacity. The remaining capacity is wind, and biomass and other renewables.

The concentration of capacity ownership among suppliers to the Alberta market can influence the ability of suppliers to take unilateral actions to increase the profits they receive from selling energy into the AWEM. Table 2 lists the generation capacity

[6] Computing the no-expected-congestion market-clearing price would require knowledge of the configuration of the transmission network each hour of the day during the sample period and access to the actual software used to dispatch generation units based on the offer curves they submit and the configuration of the transmission network. Because neither is available, an upper and lower bound on this price is computed that does not require this information. Wolak (2013) uses the full network model for the Australian wholesale electricity market to simulate a counterfactual dispatch of the short-term market to compute counterfactual reduced congestion prices.

Table 1
Installed capacity by prime mover in 2013.

Prime mover	Capacity in MW	Capacity share (%)
Coal	6232	46.29
Natural gas cogeneration	3712	27.57
Hydroelectric	879	6.53
Natural gas combined cycle	843	6.26
Wind	777	5.77
Natural gas combustion turbine	753	5.59
Biomass and other renewables	266	1.98
Total installed capacity	13,462	100.00

Table 2
Capacity controlled and capacity share of five largest firms.

Owner	Capacity (MW)	Share of system (%)
Firm A	1349	10.02
Firm B	1507	11.19
Firm C	1897	14.09
Firm D	2354	17.49
Firm E	2580	19.17
Total of five largest firms	9687	71.96

controlled by the five largest suppliers.[7] These suppliers together control more than 70% of the installed capacity in Alberta.[8] Firm E controls almost 20% of the installed capacity, followed by Firm D at 17.49%. The smallest share of system capacity belongs to Firm A which controls slightly more than 10% of the installed capacity in Alberta.

A transmission network where congestion is infrequent limits the incentive of these large suppliers to submit offer curves that reflect the exercise of substantial unilateral market power.[9] Transmission congestion occurs throughout the province, but is primarily associated with serving demand in the two largest cities in Alberta – Calgary and Edmonton – and with providing electricity to the major centers of industrial activity in the province.

The competitiveness benefits of transmission expansions in a wholesale electricity market are likely to be larger the greater is the concentration in generation capacity ownership among suppliers in the market. Because the AWEM has substantial market concentration, with the top five suppliers controlling more than 70% of the installed capacity, the competitiveness benefits of transmission expansions for this market are likely to be substantial, even if suppliers have high-levels of hourly fixed-price forward contract obligations.[10]

The highest recorded system peak demand during our sample period is 10,609 MW. This was hit on January 16, 2012. System peaks in 2009, 2010, and 2011 were within a few hundred MWs of this level. Fig. 1(a) plots the demand duration curves for the AWEM for 2009–2012, and the first seven months of 2013. The

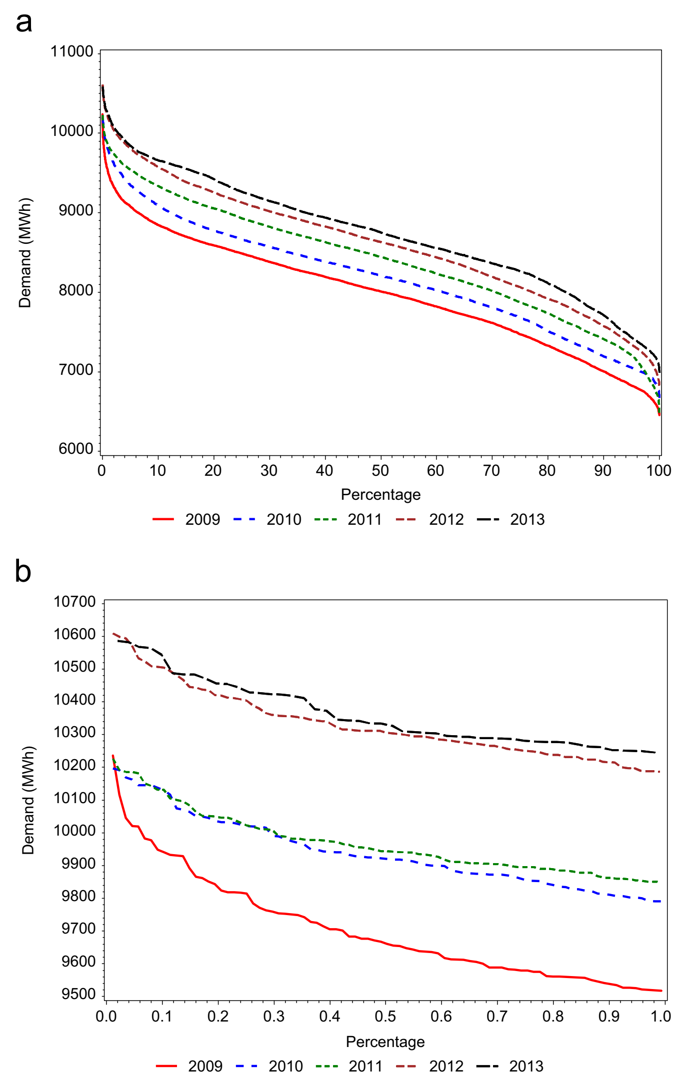

Fig. 1. (a) Demand duration curves for 2009–2013. (b) Highest 1% of demand duration curves for 2009–2013.

horizontal axis of Fig. 1(a) is the percentage of hours of the year from zero to 100 and vertical axis is the hourly demand from the highest demand hour that occurred during the year to the lowest demand hour that occurred during the year. For a given percentage value on the horizontal axis, say 70%, the MWh value on the vertical axis is the demand level that 70% of the hours of the year have demand levels above. Fig. 1(a) shows that a significant amount of generation capacity is needed less than 5% of hours of the year. Fig. 1(b) plots the portion of each curve for the 1% of the hours of the year with the highest hourly demands. For 2009, the difference between the annual peak demand and the demand at the highest 1th percentile of the hourly demand distribution is almost 700 MWh. For remaining years, this difference is closer to 300 MWh. These high levels of demand are instances when transmission constraints are likely to reduce significantly the amount of competition some of the large suppliers face for their output.

Fig. 2(a) plots the annual hourly price duration curves for 2009–2012 and the first seven months of 2013. These curves are much flatter than the demand duration curves for all but the highest 15% of the hours of all of the years. This result suggests that for demand levels that prevail during most hours of the year there are limited opportunities for the five largest suppliers to exercise substantial unilateral market power in AWEM. However,

[7] Although several generation units are jointly-owned, a single firm typically "controls" the unit in the sense that it submits the hourly offer curves to supply energy from that unit into the AESO market. The assignment of generation capacity to supplies in Table 2 is based on the entity that "controls" the generation unit.

[8] Consistent with AESO market analysis policies, the identities of individual market participants have been omitted to maintain confidentiality, although these names are consistent throughout the paper. Specifically, Firm A refers to the same firm and Firm B refers to the same firm, and so on, in all tables and figures.

[9] McRae and Wolak (2009) provide a graphical analysis of the impact of transmission constraints on a supplier's ability to exercise unilateral market power.

[10] As shown in McRae and Wolak (2014), suppliers with hourly fixed price forward contract obligations close to the hourly output of their generation units have a significantly reduced incentive to exploit their ability to exercise unilateral market power. The interaction between transmission expansions and the incentive of large suppliers to enter into fixed price forward contracts is discussed in the conclusions and policy implications section following the presentation of the empirical results.

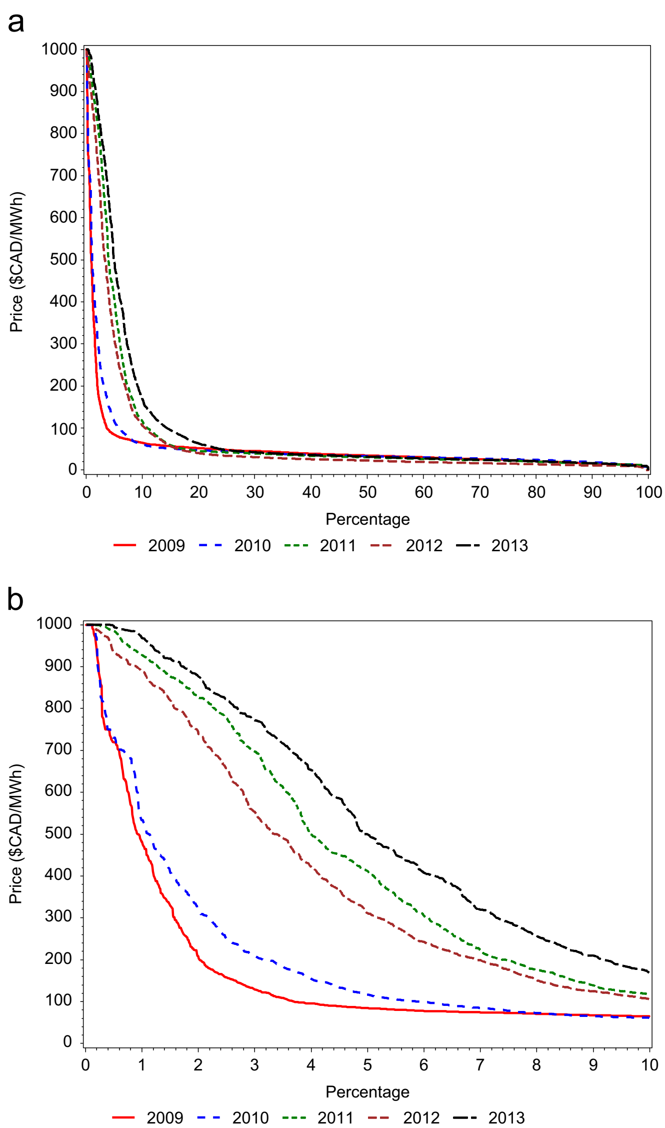

Fig. 2. (a) Price duration curves for 2009–2013. (b) Highest 10% of price duration curves for 2009–2013.

for the highest-priced 10–15% of the hours of the year, the curves become extremely steep, which is consistent with the earlier logic that the high levels of concentration of generation unit ownership can allow significant amounts of unilateral market power to be exercised during a small percentage of the hours of the year. Fig. 2 (b) plots the price duration curve for the highest 10% of hours of the year. For 2009 and 2010, this curve does not start to become steep until the highest 3% of hours of the year, whereas for the other years this curve increases at close to a constant rate for the 10th percentile to the highest priced hour of the year.

The consumer benefits of transmission expansions also depend on the mechanism that translates the offer curves generation unit owners submit into the prices they are paid for the energy they produce.[11] The same transmission expansion is likely to have a different magnitude of competitiveness benefits, depending on the form of the offer curves suppliers submit and the mechanism – nodal-pricing, zonal-pricing and single-zone pricing – used to set the prices paid to generation unit owners in that market. Generators in Alberta are able to submit up to seven price and quantity pairs for each hour of the day for each generation unit in their portfolio. If (p_{ik},q_{ik}) $i=1,2,3\ldots,7$ is the set of price level and quantity increment pairs for generation unit k $(k=1,2,..,K)$ owned by the supplier, then that supplier's aggregate offer curve is a non-decreasing step function with the height of each step equal to an offer price and the length of the step equal to the sum of the total amount of quantity increments across all generation units in that supplier's portfolio associated with that offer price.

Call the aggregate offer curve for supplier n during hour h, $S_{nh}(p,\Theta_n)$, where Θ_n is the $14(K_n)$-dimensional vector of offer price and quantity increment pairs for the K_n generation units owned by supplier n. This curve gives the maximum amount of energy supplier n is willing to sell at price p during hour h. If there is no transmission congestion, then the market-clearing price is determined as the price where the aggregate supply curve intersects the aggregate demand during hour h, QD_h. Mathematically, the market-clearing price, p^*, solves

$$S_{1h}(p,\Theta_1)+S_{2h}(p,\Theta_2)+\ldots+S_{Nh}(p,\Theta_N)=QD_h, \tag{1}$$

where N is the total number of suppliers submitting offer curves during hour h.

When there is transmission congestion that prevents the AESO from accepting a supplier's quantity increment, this quantity increment and its associated offer price is dropped from that supplier's offer curve. Define $SC_{nh}(p,\Theta_n)$ as the transmission-constrained offer curve for supplier n during hour h. By definition, the following inequality holds all hours (h) and suppliers (n)

$$SC_{nh}(p,\Theta_n)\le S_{nh}(p,\Theta_n) \text{ for all } p \tag{2}$$

and holds as a strict inequality for all prices greater than the lowest offer price at which a quantity increment cannot be accepted because of transmission constraints. Consequently, when there are transmission constraints, the market-clearing price, p^*, solves

$$SC_{1h}(p,\Theta_1)+SC_{2h}(p,\Theta_2)+\ldots,+SC_{Nh}(p,\Theta_N)=QD_h, \tag{3}$$

Fig. 3 plots the aggregate offer curve not accounting for transmission constraints (called the Ideal Aggregate Offer Curve) and the offer curve with transmission constraints accounted for (called the Feasible Aggregate Offer Curve) for hour 12 of May 12, 2010. The vertical line in the graph is QD, the aggregate demand during that hour. The two curves satisfy inequality (2) for all positive prices. Moreover, point of intersection of QD_h with the Ideal Aggregate Offer Curve yields a price that is much lower than the price at the intersection of the Feasible Aggregate Offer Curve, which determines the actual market-clearing price. The difference between the prices at the two points of intersection is almost 800 CAD/MWh. This price difference indicates the potential for significant consumer benefits from eliminating the transmission congestion that led to the need to use Eq. (3) to set the market-clearing price rather than Eq. (1).

If expected profit-maximizing suppliers believe that the transmission-constrained or Feasible Aggregate Offer Curve will be used to set prices rather than the unconstrained or Ideal Aggregate Offer Curve, these suppliers are likely to submit offer curves that make less capacity available at every output level relative to the case where they believe that the Ideal Aggregate Offer Curve will be used to set price. The converse of this logic implies if each of the five large suppliers believes that none of the quantity increment offers of its competitors will be prevented from selling energy because of transmission constraints, then each strategic supplier will find it expected profit-maximizing to submit an offer curve closer to its marginal cost curve. This will yield lower market-

[11] Awad et al. (2011) measures the competitiveness benefits of a transmission expansion for a nodal-pricing short-term market and Wolak (2013) measures the competitiveness benefits of a transmission expansion for a zonal-pricing short-term market.

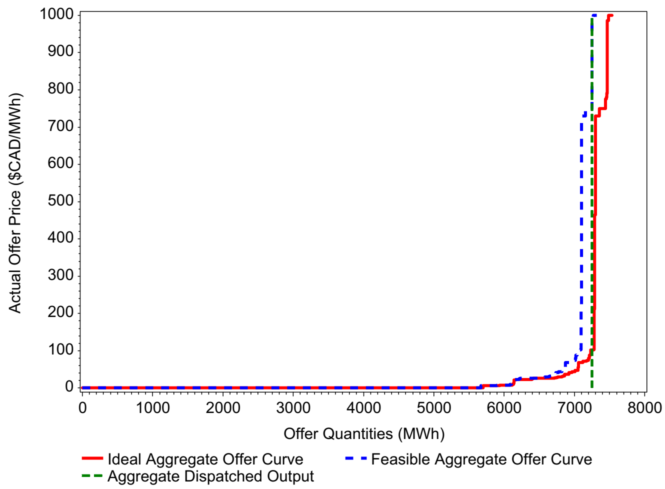

Fig. 3. Ideal and Feasible Aggregate Offer Curve for hour 12 of 5/12/2010.

clearing prices, whether or not some of its competitors' offer quantity increments are ultimately constrained from actually selling energy.

Transmission expansions that increase the competitiveness of the short-term market can also increase the incentive strategic suppliers have to sell fixed-price forward contracts for energy. A supplier with the ability to exercise unilateral market power that faces greater competition more hours of the year (as a result of increased transmission capacity) has an increased incentive to enter into fixed-price forward contracts that commit it to produce a higher level of output in the short-term market. This higher market-wide level of fixed-price forward contract coverage of final demand leads all suppliers to submit offer prices closer to their marginal cost of production, which yields market prices closer to competitive benchmark levels. These lower market prices from the increased level of fixed-price forward contracting by strategic suppliers are an additional source of benefits to electricity consumers from a higher capacity transmission network.

The analysis in this paper does not capture this forward contracting source of consumer benefits from transmission expansions. It only models the change in offer behavior brought about by each strategic supplier facing a more elastic residual demand curve because of the increased number of suppliers able to compete against it to supply energy because of the transmission expansion, not the change in that supplier's forward contracting decision and the forward contracting decisions of its competitors resulting from this transmission expansion.

The next section describes how I estimate the change in each strategic supplier's offer curve in response to that supplier's belief that transmission constraints will not limit the competition that it faces for its output. The approach uses insights from the model of expected profit-maximizing offer behavior developed in Wolak (2000, 2003 and 2007) to derive an upper bound and a lower bound on the "no-perceived-congestion" market-clearing price that assumes no change in forward contracting behavior by the five large strategic suppliers.

3. Computing the "perceived no-congestion" offer curves and counterfactual market-clearing prices

This section summarizes the basic features of the model of expected profit-maximizing offer behavior introduced in Wolak (2000) and tested empirically in Wolak (2003, 2007). This model of expected profit-maximizing offer behavior and the empirical analysis in McRae and Wolak (2014) is the foundation for the procedure used here to compute the "no-perceived-congestion" offer curve for each of the five largest suppliers. These counterfactual offer curves and the actual offer curves of other, non-top five, suppliers are combined to form the no-expected-congestion counterfactual aggregate offer curves used to compute the counterfactual no-expected congestion market prices.

The empirical modeling framework is based on the assumption that each supplier chooses its offer curve to maximize its expected profits from selling energy given the distribution of aggregate demand and the supply uncertainty of its competitors, which creates a distribution of residual demand curve realizations that the supplier faces. As discussed in Wolak (2000), an expected profit-maximizing supplier picks the vector of parameters of its aggregate offer curve, Θ in the notation of the previous section, to maximize the expected value of the realized profits over the distribution of residual demand curves that it faces, subject to the constraints placed on the elements of Θ by the market rules. For example, in the AESO, all offer prices must be greater than or equal to zero and less than the offer cap, which was 1000 CAD/MWh during the sample period. The offer quantity increments must be greater than or equal to zero and their sum less than or equal to the available capacity of the generation unit.

The price at the point of intersection of the supplier's offer curve with each residual demand realization determines the market-clearing price and amount of output that the supplier sells in the short-term market for that realization of residual demand uncertainty. This price and quantity pair, along with the supplier's variable cost function, determines the supplier's realized variable profits for that residual demand realization.

It is important to emphasize that the assumption that suppliers maximize expected profits subject to the strategies of other market participants and the realizations of all supply and demand uncertainties is equivalent to that supplier exercising all available unilateral market power. A market participant is said to possess the ability to exercise market power if it can take unilateral actions to influence the market price and profit from the resulting price change, which is only possible if it faces a downward sloping residual demand curve.

If a transmission upgrade changes the distributions of residual demand curves that suppliers with the ability to exercise unilateral market power face, then the expected profit-maximizing offer curve that each of these suppliers submits should change. The remainder of this section describes how I estimate the change in offer behavior as a result of reducing the incidence of transmission congestion and how this change in offer behavior by the five strategic suppliers impacts market-clearing prices.

3.1. Measuring the ability to exercise unilateral market power in bid-based markets

The residual demand curve that a supplier faces determines its ability to exercise unilateral market power. It is constructed from the offer curves submitted by all market participants besides the one under consideration. Let $S_n(p)$ denote the ideal hourly offer curve of supplier n and $SC_n(p)$ the feasible hourly offer curve of suppler n that accounts for transmission constraints.[12] At each price, p, the function $S_n(p)$ gives the total quantity of energy that supplier n is willing to sell and the function $SC_n(p)$ gives the amount of energy supplier n is able to sell given the level and geographic location of demand, the offer curves submitted by its competitors and the configuration of the transmission network.

[12] For notational simplicity, the dependence of the hourly offer curve on Θ_n and the hour subscript h is suppressed in this section.

As shown in Fig. 3, the offer curves for each supplier can be used to construct the Ideal Aggregate Offer Curve and the Feasible Aggregate Offer Curve. Eq. (1) can be re-arranged to derive the Ideal Residual Demand Curve for any supplier, which measures the ability of the supplier to exercise unilateral market in the absence of transmission constraints. To measure this ability of supplier j to exercise unilateral market power, Eq. (1) can be re-written as

$$S_j(p) = \mathrm{QD} - (S_1(p) + S_2(p) + \ldots + S_{j-1}(p) + S_{j+1}(p) + \ldots + S_N(p)) \\ = \mathrm{QD} - \mathrm{SO}_j(p), \tag{4}$$

where $\mathrm{SO}_j(p)$ is the aggregate willingness-to-supply curve of all firms besides supplier j. We define $\mathrm{DR}_j{}^I\left(p\right) = \mathrm{QD} - \mathrm{SO}_j\left(p\right)$ as the Ideal Residual Demand Curve facing supplier j. The ideal residual demand of supplier j at price p is defined as the market demand remaining to be served by supplier j after the ideal willingness-to-supply curves, $S_k(p)$ for all $k \neq j$, have been subtracted out.

The Feasible Residual Demand Curve facing supplier j can also be computed by re-arranging Eq. (3) in an analogous manner. This residual demand curve captures supplier j's ability to exercise unilateral market power given the actual configuration of the transmission network, the location of demand, and the locations of other generation units. In this case, Eq. (3) can be re-written as

$$\mathrm{SC}_j(p) = \mathrm{QD} - (\mathrm{SC}_1(p) + \mathrm{SC}_2(p) + \ldots + \mathrm{SC}_{j-1}(p) + \mathrm{SC}_{j+1}(p) + \ldots \\ + \mathrm{SC}_N(p)) \\ = \mathrm{QD} - \mathrm{SCO}_j(p), \tag{5}$$

where $\mathrm{SCO}_j(p)$ is the aggregate feasible willingness-to-supply curve of all firms besides supplier j. We define $\mathrm{DR}_j{}^F\left(p\right) = \mathrm{QD} - \mathrm{SCO}j\left(p\right)$ as the Feasible Residual Demand Curve facing supplier j. The feasible residual demand for supplier j at price p is defined as the market demand remaining to be served by supplier j after the feasible willingness-to-supply curves, $\mathrm{SC}_k(p)$ for all $k \neq j$, have been subtracted out.

Eq. (2) implies the following relationship between the Ideal and Feasible residual demand curves

$$DR_j^F(p) \geq DR_j^I(p) \text{ for all } p. \tag{6}$$

This relationship holds as a strict inequality for all prices greater than the lowest offer price associated with the first quantity offer from any firm besides supplier j that is prevented from being accepted to supply energy because of the configuration of the transmission network. This logic also implies that at each price level the Feasible Residual Demand Curve is at least as flat as the Ideal Residual Demand Curve.

Fig. 4(a)–(e) plots the Ideal and Feasible residual demand curves for the five largest suppliers in the Alberta market for hour 13 of May 16, 2010. The vertical line on each graph shows how much energy the supplier actually sold during that hour. For all but Firm C, the point of intersection between the Ideal Residual Demand Curve and the amount that the firm actually sold occurred at price that was substantially lower than price at which the Feasible Residual Demand curve intersected the amount the firm actually sold. The point of intersection of each Feasible Residual Demand curve with the suppliers' actual output during the hour is equal to market-clearing price during that hour.

The prospect of facing a substantially steeper distribution of Feasible Residual Demand Curves would cause an expected profit-maximizing large supplier to submit a higher offer price for its output than it would if it faced the flatter distribution of Ideal Residual Demand Curves. Because the offer curve each supplier actually submitted and what Feasible Residual Demand Curve it actually faced is observed ex post, using insights from the model of expected profit-maximizing offer behavior in Wolak (2000), the approach of McRae and Wolak (2014) can be used to estimate a predictive relationship between a supplier's hourly offer price and the shape of the residual demand curve that it actually faced. This predictive relationship can then be used to estimate how the supplier's offer price would change as a result of facing the Ideal Residual Demand Curve instead of the Feasible Residual Demand Curve.

3.2. Measuring of the ability to exercise unilateral market power from a simplified model of expected profit-maximizing offer behavior

This section develops a simplified model of expected profit-maximizing offer behavior that motivates the linear regression model estimated to predict how the hourly offer price of each of the five large strategic suppliers will change in response to facing the Ideal Residual Demand Curve for that hour instead of the Feasible Residual Demand Curve for that hour. This linear regression model has been employed by McRae and Wolak (2014) to predict how strategic suppliers in the New Zealand wholesale electricity market will change their half-hourly offer prices in response to changes in the form of the half-hourly residual demand curve they face. McRae and Wolak (2014) found that even after controlling for differences in input fuel costs across days of their sample, when each of the four large New Zealand suppliers faced less competition, as measured by the half-hourly value of the inverse semi-elasticity of their residual demand curve, each of the firms was predicted to submit a significantly higher half-hourly offer price.

Fig. 5(a) illustrates the construction of an expected profit-maximizing willingness to supply curve for the case of two possible continuously differentiable residual demand curve realizations. For each residual demand curve realization, intersect the marginal cost curve with the marginal revenue curve associated with that residual demand curve realization. For Residual Demand Curve 1 the marginal revenue curve for this residual demand curve (not shown in the figure) intersects the marginal cost curve at the quantity Q_1. The output price associated with this output level on Residual Demand Curve 1 is P_1. Repeating this process for Residual Demand Curve 2 yields the profit-maximizing price and quantity pair (P_2,Q_2). Note that because both residual demand curves are very steeply sloped, there is a substantial difference between the market price and the marginal cost at each output level. If these two residual demand realizations were the only ones that the supplier faced, its expected profit-maximizing offer curve would pass through both of these points because for each residual demand realization this offer curve would cross at an ex post profit-maximizing level of output. The straight line connecting the points (P_1,Q_1) and (P_2,Q_2) in the figure is one possible expected profit-maximizing offer curve.

To illustrate the impact of a flatter residual demand curve distribution on the offer curves submitted by an expected profit-maximizing supplier, Fig. 5(b) repeats the construction of an expected profit-maximizing offer curve for the case of two more elastic residual demand curve realizations. The line connecting the points (P_1,Q_1) and (P_2,Q_2), which is an expected profit-maximizing offer curve for these two residual demand realizations, is much closer to the supplier's marginal cost curve. Specifically, for each residual demand realization, the price associated with the profit-maximizing level of output for that residual demand curve realization is closer to the marginal cost of producing that level of output than it was in Fig. 5(a). This outcome occurs because each residual demand realization is much flatter than each residual demand curve realization in Fig. 5(a).

Fig. 5(c) considers the case in which the two residual demand curve realizations are infinitely elastic, meaning that for each realization the supplier faces enough competition that the entire

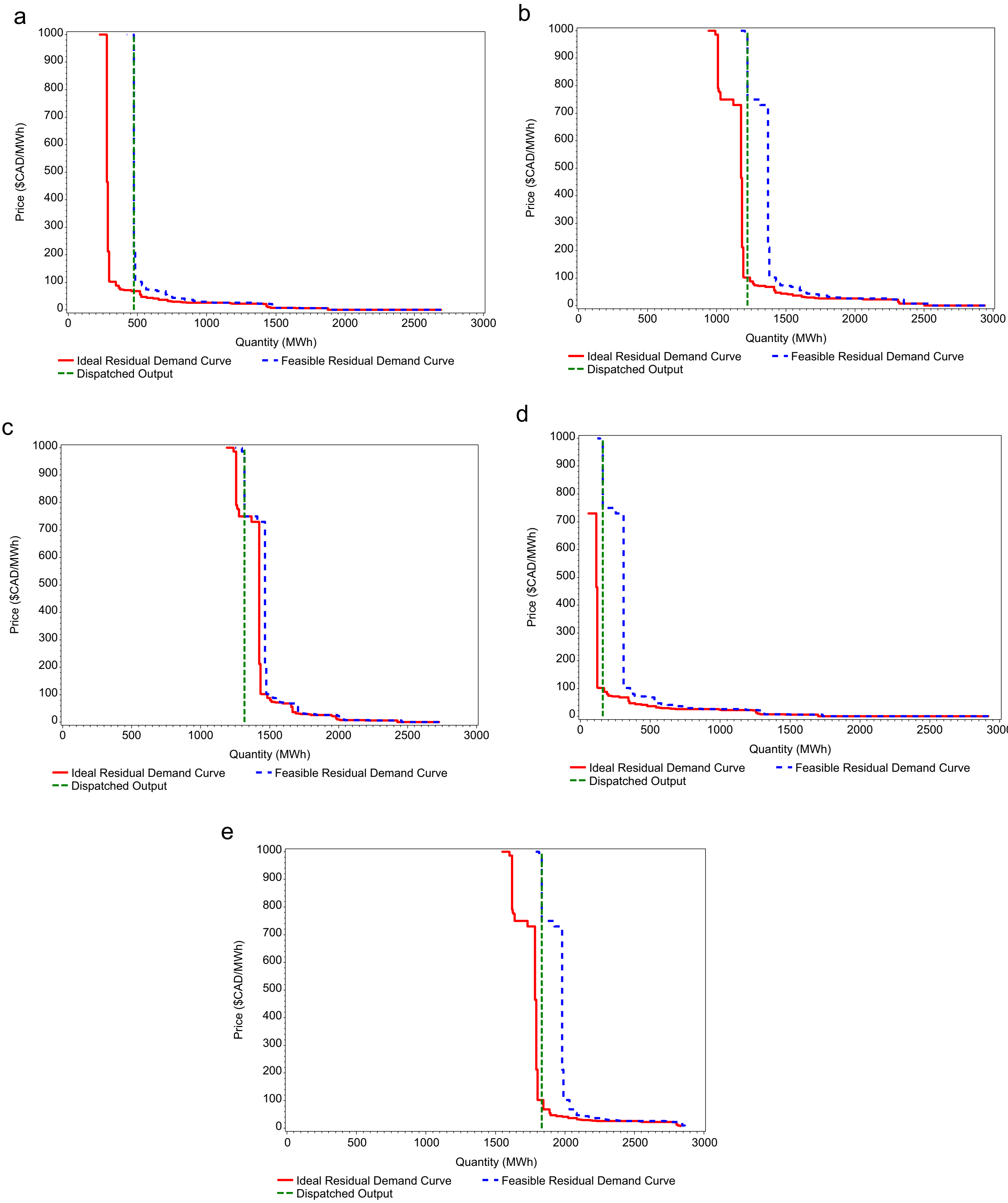

Fig. 4. (a) Ideal and Feasible Residual Demand Curves for Firm A, hour 12 of 5/12/2010. (b) Ideal and Feasible Residual Demand Curves for Firm B, hour 12 of 5/12/2010, (c) Ideal and Feasible Residual Demand Curves for Firm C, hour 12 of 5/12/2010, (d) Ideal and Feasible Residual Demand curves for Firm D, hour 12 of 5/12/2010, and (e) Ideal and Feasible Residual Demand Curves for Firm E, hour 12 of 5/12/2010.

market can be satisfied by other suppliers at a particular price. By the logic described above, the supplier will find it unilaterally profit-maximizing to produce at the intersection of each residual demand curve realization with its marginal cost curve, because the marginal revenue curve for each residual demand realization is equal to the residual demand curve. In this case, the supplier's

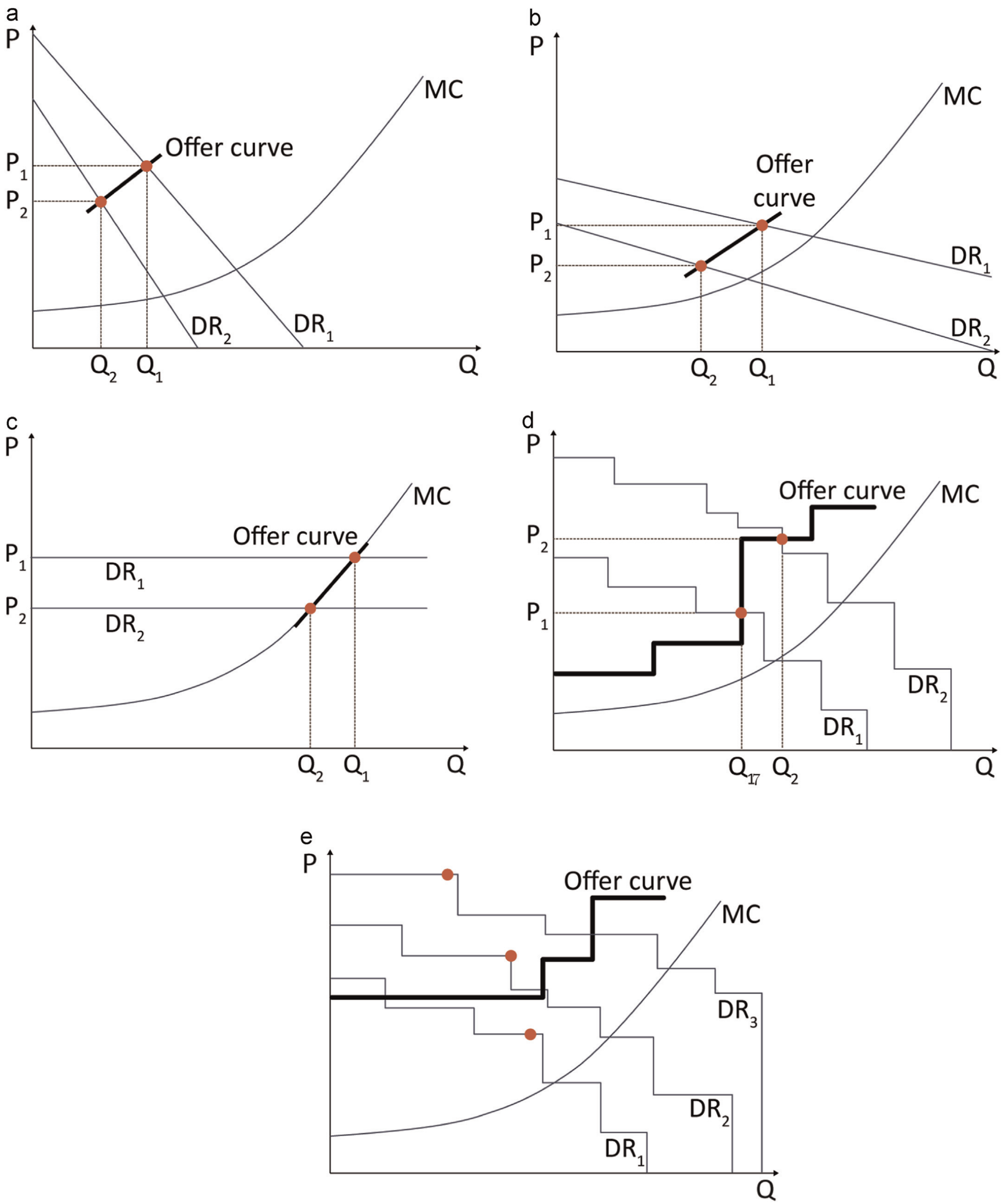

Fig. 5. (a) Derivation of expected profit-maximizing offer curve. (b) Expected profit-maximizing offer curve (flatter residual demand curves), (c) Expected profit-maximizing offer curve (perfectly elastic residual demand curves), (d) Impact of step functions on expected profit-maximizing offer curve. (e) Expected profit-maximizing step-function offer curve.

expected profit-maximizing offer curve, the line connecting the profit-maximizing output levels for each residual demand curve realization, is equal to the supplier's marginal cost curve. This result illustrates a very important point that if a supplier faces sufficient competition for all possible residual demand curve realizations then it will find it unilaterally expected profit-maximizing to submit an offer curve equal to its marginal cost curve.

The examples in Fig. 5(a)–(c) utilize continuously differentiable residual demand curves. However, the same process can be followed to compute an expected profit-maximizing offer curve for the case of step-function residual demand curves. Fig. 5(d) shows how this would be done for the more realistic case of step function residual demand curves with two possible residual demand realizations. For each residual demand curve realization, the supplier would compute the ex post profit-maximizing level of output and market price for the marginal cost curve given in Fig. 5(d). For DR_1 this is the point (P_1,Q_1) and for DR_2 this is the point (P_2,Q_2). If these two residual demand curve realizations were the only possible residual demand curve realizations that the supplier could face, any of the many step function offer curves consistent with the market rules that passes through these two points would be an expected profit-maximizing offer curve. One such non-decreasing step function is shown in Fig. 5(d).

Unfortunately, computing the expected profit-maximizing offer curve for a supplier is generally more complex than passing an offer curve through the set of ex post expected profit-maximizing price and output quantity pairs for every possible residual demand curve realization. That is because the market rules can prevent a supplier from achieving the ex post profit-maximizing market price and output quantity pairs for all possible residual demand realizations. Specifically, unless all of these ex-post profit-maximizing price and quantity pairs lie along a willingness-to-supply curve for the supplier that the market rules allow it to submit, it is not possible for the supplier to submit a willingness to supply curve that always crosses the realized residual demand curve at an ex post profit-maximizing price and quantity pair for that residual demand curve realization.

Fig. 5(e) provides an example of this phenomenon. This figure shows the ex post profit-maximizing price and quantity pairs for three residual demand curve realizations. Note that the profit maximizing point for DR_2 lies below and to the right of the profit maximizing point for DR_3. The same statement holds for DR_1 and DR_2. This makes it impossible for the supplier to submit a non-decreasing step function offer curve that passes through the three ex post profit-maximizing price and output quantity pairs. In this case, the supplier must know the probability of each residual demand curve realization in order to choose the parameters of its expected profit-maximizing willingness to supply curve.

Fig. 5(e) demonstrates that the expected profit-maximizing offer curve need not pass through any of these three ex post profit-maximizing price/quantity pairs. Instead, as discussed in Wolak (2003, 2007, 2010), the form of the expected profit-maximizing offer curve depends on both the form of each residual demand curve realization and the probability of that residual demand curve realization. This curve, shown in Fig. 5(e), yields market-clearing price and quantity-sold pairs for the firm for each of the three residual demand curve realizations that maximizes the expected profits the firm earns subject to this offer curve being in the set of offer curves the market rules allow a supplier to submit.

Although the approach to computing expected profit-maximizing offer curves consistent with wholesale market rules presented in Wolak (2003, 2007) is considerably more complex than the process outlined in Fig. 5(a)–(c), the basic intuition from the simplified approach in these figures holds for the general case of step function residual demand curves. Specifically, when a supplier faces a flatter distribution of step function residual demand realizations, it will find it expected profit-maximizing to submit a step function willingness-to-supply curve with offer prices closer to its marginal cost of production.

Following McRae and Wolak (2014), the simplified model of expected profit-maximizing offer behavior is used to derive a summary measure of the hourly ability of a supplier to exercise unilateral market power from the realized residual demand curve that the supplier faced during that hour. This measure, called the Inverse Semi-Elasticity of the realized residual demand curve at the actual market-clearing price provides an ex post measure of the hourly ability of a supplier to exercise unilateral market power. Specifically, this inverse semi-elasticity quantifies the \$/MWh increase in the market-clearing price for that hour that would have occurred if the supplier had reduced the amount of output it sold that hour by one percent.

As shown in McRae and Wolak (2014), the simplified model of expected profit-maximizing offer behavior described in Fig. 5(a)–(c) implies a linear relationship between the offer price along the supplier's offer curve, its marginal cost of production and the inverse semi-elasticity of the realized residual demand curve. The first-order conditions for ex-post profit-maximization for the two residual demand realizations in Fig. 5(a) imply:

$$P_i = C_i - \left[DR_i(P_i)/DR_i{'}(P_i)\right],\ i = 1, 2. \tag{7}$$

Eq. (7) implies that the offer price for the supplier at its output level for residual demand curve realization 1 or 2 (P_i for $i=1,2$) is equal to the marginal cost of the highest cost unit owned by that supplier operating for that residual demand curve realization (C_i for $i=1,2$) plus the value of the residual demand curve at that offer price divided by the absolute value of the slope of the residual demand curve at that offer price for the residual demand curve realization ($[DR_i(P_i)/DR_i{'}(P_i)]$ for $i=1,2$).

We define η_i ($i=1,2$) as the inverse semi-elasticity of the residual demand curve i as

$$\eta_i = -(1/100)\left[DR_i(P_{mkt})/DR_i{'}(P_{mkt})\right]. \tag{8}$$

at the market price, P_{mkt}. This magnitude gives the \$/MWh increase in the market-clearing price associated with a one percent reduction in the amount of output sold by the supplier. Note that at $P_{mkt,}$ the market-clearing price, $DR_i(P_{mkt})$ is equal to supplier i's actual level of output. In terms of this notation, Eq. (7) becomes

$$P_i = C_i + 100\eta_i,\ i = 1, 2. \tag{9}$$

Thus, the simplified model of expected profit-maximizing offer behavior implies that higher hourly offer prices for the supplier should be associated with higher values of the hourly inverse semi-elasticity.

As discussed above, offer curves in the AWEM are step functions, so that defining a value of η_i, the inverse semi-elasticity, for a step function residual demand curve requires choosing a method for computing a finite difference approximation to the slope of the residual demand curve at a specific value of the market price. This logic also implies that because actual residual demand curves are step functions, Eq. (9) will not hold with equality for the computed values of the inverse semi-elasticity. However, the general model of expected profit-maximizing offer behavior with step function offer curves and residual demand curves presented in Wolak (2003, 2007) implies that when a supplier has a greater ability to exercise unilateral market power as measured by the size of η_i, that supplier's offer price is likely to be higher relative to the supplier's marginal cost of production.

McRae and Wolak (2014) present empirical evidence consistent with this hypothesis for the four largest suppliers in the New Zealand wholesale electricity market. This predictive relationship between a supplier's hourly offer price and the hourly value of η_i (that only holds exactly for the simplified model of expected profit-maximizing offer behavior with continuously differentiable residual demand curves in Fig. 5(a)–(c)) is estimated empirically for the five largest suppliers in Alberta in order to compute the counterfactual no-perceived congestion offer curves for these five suppliers.

The method for calculating the finite difference slope of the step-function residual demand curve at the firm's actual hourly output level requires choosing the output change used to compute the finite-difference approximation to the slope. McRae and Wolak (2014) experimented with a number of approaches to computing this finite difference approximation to the slope and found that their empirical results were largely invariant to the approach used. Their preferred approach is employed to compute the finite difference slope of the residual demand curve that enters into the computation of the hourly inverse semi-elasticity of the residual demand curve for each strategic supplier.

3.3. The counterfactual no-perceived-transmission-constraints offer curve

This section describes the process used to construct the counterfactual offer curve under the assumption of no perceived transmission constraints for each of the five large suppliers. Specifically, each supplier expects to face the Ideal Residual Demand Curve rather than the Feasible Residual Demand Curve. I first compute the hourly inverse semi-elasticity of the Feasible Residual Demand curve facing each strategic supplier for the entire sample period. Then for each strategic supplier, I estimate a predictive regression relating the supplier's hourly offer price at its actual output level for that hour on day-of-sample and hour-of-day fixed effects (that control for across-day changes in input prices and within-day variation in operating costs) and the hourly inverse semi-elasticity of the Feasible Residual Demand Curve faced by that supplier at its actual output level.

The coefficient estimate on the hourly feasible inverse semi-elasticity is used to compute the predicted change in the supplier's offer price as a result of facing the Ideal Residual Demand Curve instead of the Feasible Residual Demand Curve. This $/MWh offer price change is applied to all offer prices along that firm's willingness-to-supply curve.[13] The process is repeated for all hours of the sample period to compute a counterfactual no-perceived-congestion offer curve for each hour of the sample period. This process is then repeated for all strategic suppliers.

Fig. 7(a)–(e) plots the daily averages of the inverse semi-elasticities of the Feasible Residual Demand Curve for hour h for supplier n (n=A, B, C, D, and E), $n^F{}_{nh}$, for each hour of the day over the sample period January 1, 2009 to July 31, 2013. Each figure also plots the corresponding daily averages of the inverse semi-elasticities for Ideal Residual Demand Curve for the hour h, $n^I{}_{nk}$, for the same five suppliers for each hour of the day. Consistent with the fact that for any interval of offer prices, the Ideal Residual Demand Curve contains at least as many quantity increments as the Feasible Residual Demand Curve, the absolute value of the finite difference estimate of $\mathrm{dDR}_j{}^F(p)/\mathrm{d}p$ is less than or equal to the absolute value of the finite difference estimate of $\mathrm{dDR}_j{}^I(p)/\mathrm{d}p$ for all hours in the sample. This result implies that the sample mean of $\eta_{nh}{}^F$ is greater than the sample mean of $\eta_{nk}{}^I$ for all hours of the day for all five strategic suppliers. As shown in the figure for each supplier, the differences between the hourly means of the two inverse semi-elasticities are much larger during the peak demand hours of the day when transmission constraints likely render more quantity offers unable to be accepted to supply energy. This result

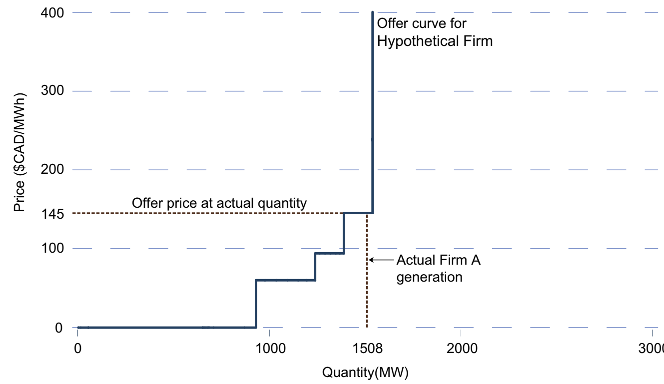

Fig. 6. Sample calculation of hourly offer price for hypothetical firm.

is consistent with more of the competitiveness benefits of transmission investments being realized during the high demand hours of the day, week, and year.

In order to describe the predictive regression estimated to determine the change in each strategic supplier's offer price as a result of facing the Ideal Residual Demand Curve instead of the Feasible Residual Demand Curve, a definition of a supplier's hourly offer price is required. Fig. 6 presents the hourly offer curve for a hypothetical firm. The dispatched quantity of energy for the hypothetical firm during that hour is 1508 MW. The offer price along the firm's offer curve for that hour, the dependent variable of the regression, is found by extending a vertical line up from the horizontal axis at 1508 MW until it intersects the firm's willingness-to-supply curve. In this case, the offer price for the quantity of energy dispatched for this firm is equal to $CAD 145/MWh, which is the offer step directly above the quantity level 1508 MW. In general, the offer price for output level Q^* for supplier k during hour h is computed as the solution to the following equation in P: $Q^* = S_{nh}(P)$, where $S_{nh}(P)$ is the supplier n's willingness-to-supply curve during hour h.

The intuition from Eq. (9) of the simplified model of expected profit-maximizing offer behavior by a supplier facing a distribution of downward sloping continuously differentiable residual demand curves implies that,

$$P_{nh} = C_{nh} + \beta\eta_{nh}^F + \varepsilon_{nh} \tag{10}$$

where P_{nh} is the offer price of supplier n during hour h, C_{hn} is the marginal cost of the most expensive generation unit controlled by supplier n that is operating during hour h, and η_{nh}^F is the finite difference inverse semi-elasticity of the Feasible Residual Demand Curve facing supplier n during hour h, and β is an unknown parameter to be estimated. The error term, ε_{nh}, accounts for the fact that Eq. (10) does not hold as an equality for step function residual demand curves and the fact that η_{nh}^F is computed using finite differences along step function residual demand curves. Eq. (10) implies that after controlling for the opportunity cost of the highest cost generation unit operating during that hour, C_{nh}, a supplier's offer price at the quantity of energy that it sells in the short-term market, $P_{nh,}$ should be an increasing function of the value of the inverse semi-elasticity it faced during that hour, η_{nh}^F.

Let P_{jhdm}(offer) equal the offer price at the actual level of output sold by supplier j during hour h of day d during month of sample m. Let $\eta_{jhdm}{}^F$ equal the inverse semi-elasticity of supplier j's Feasible Residual Demand Curve during hour h of day d during month of sample m at supplier j's actual level of output. I account for differences across hours during our sample period in the variable cost of the highest cost generation unit owned by that supplier operating during hour h by including day-of-sample fixed effects

[13] The two-step procedure of (1) using the estimated predictive relationship between a supplier's offer price and the inverse semi-electricity it faces and (2) adjusting the supplier's offer price to account for the facing an Ideal residual demand curve instead of a Feasible residual demand curve can be applied to other portions of the supplier's offer curve. Experiments with this approach did not yield significantly different empirical results, so in the interest of simplicity, I adopted a single CAD/MWh adjustment applied all offer prices.

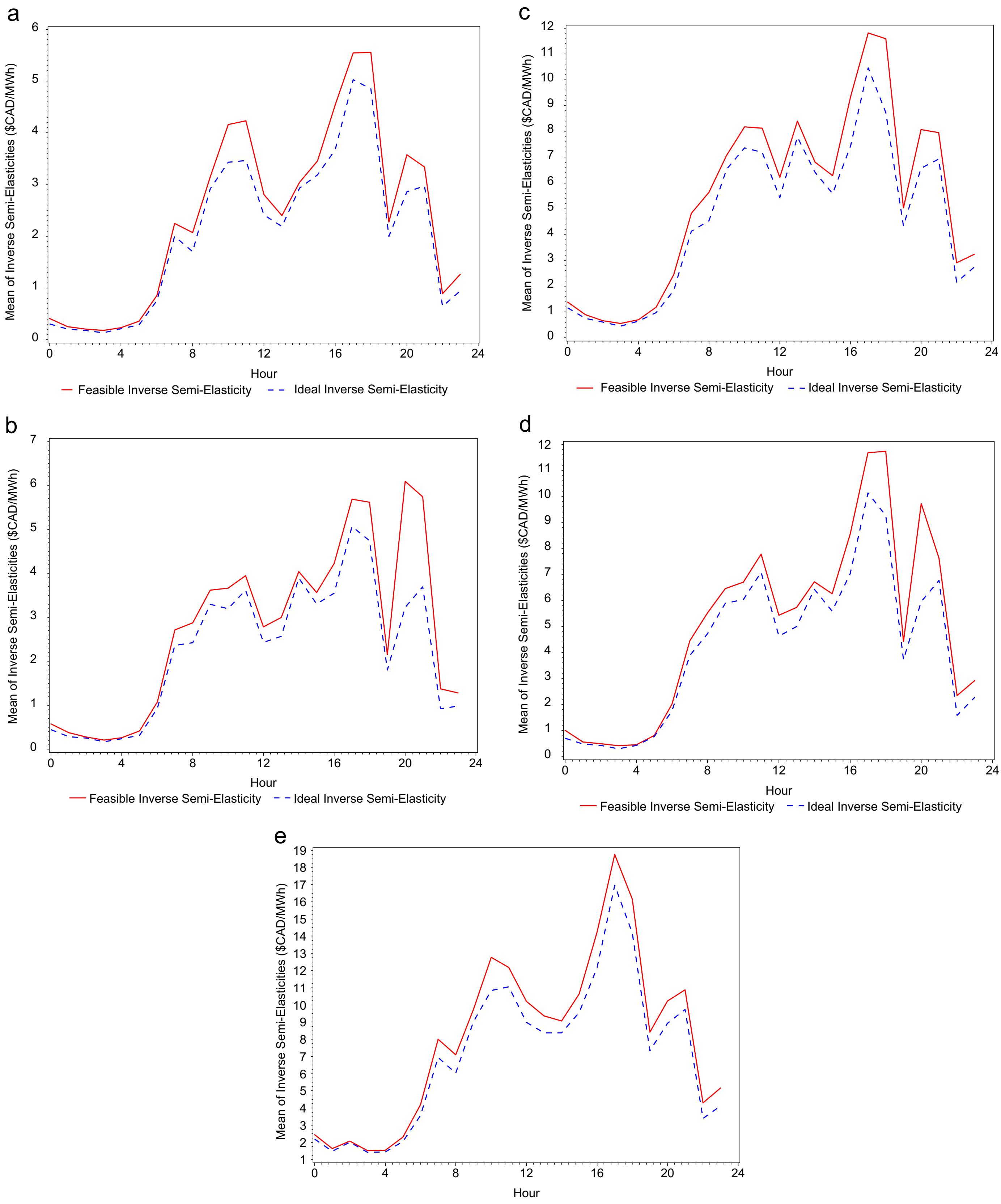

Fig. 7. (a) Mean hourly feasible and ideal inverse semi-elasticities Firm A. (b) Mean hourly feasible and ideal inverse semi-elasticities Firm B. (c) Mean hourly feasible and ideal inverse semi-elasticities Firm C. (d) Mean hourly feasible and ideal inverse semi-elasticities Firm D. (e) Mean hourly feasible and ideal inverse semi-elasticities Firm E.

and hour-of-day fixed effects for each supplier. The following regression is estimated for each supplier j:

$$P_{jhdm}(\text{offer}) = \alpha_{dmj} + \tau_{hj} + \beta_j \eta^F_{jhdm} + \varepsilon_{jhdm}, \tag{11}$$

where the α_{dmj} are day-of-sample fixed effects and the τ_{hj} are hour-of-the-day fixed effects for supplier j. The ε_{jhdm} are mean zero mean predictive regression errors. Because Eq. (9) does not hold exactly for expected profit-maximizing offer behavior with step function offer curves, I assume that Eq. (11) only recovers a consistent estimate of the best linear predictor function for a supplier j's hourly offer price (P_{jhdm}(offer)) given its hourly ability to exercise unilateral market power ($\eta jhd_m{}^F$). Because Eq. (11) is a best linear predictor function, the standard errors for the estimates of β are computed using the expression given in White (1980).

These fixed effects control for variation in costs and operating conditions across days of the sample and within days. Input fossil fuel prices and hydroelectric water levels change at most on a daily basis. Because there is a different fixed effect for each day during our sample period, these fixed effects account for the impact of daily changes in input fossil fuel prices and water levels during our sample period. The hour-of-day fixed-effects account for differences across hours of the day in the variable cost of the highest cost generation unit operating in that supplier's portfolio. This strategy for controlling for variable cost changes across hours of the sample implies that more than 1670 parameters determine the hourly variable cost values for each supplier over the sample period. Multiplying this figure by five implies more than 8850 parameters account the hourly variable cost of the highest cost generation unit operating during each hour of the sample across the five strategic suppliers.

Table 3 presents the point estimates of β_j and the associated robust standard errors from estimating Eq. (11) for each of the five largest suppliers over our sample period of January 1, 2009–July 31, 2013. The estimated values of β_j are positive, precisely estimated, and economically meaningful for all regressions.

Each of these regression coefficient estimates implies that holding all other factors constant, if the hourly inverse semi-elasticity of the residual demand curve faced by one of the five large suppliers falls, then the hourly offer price for that firm is predicted to fall by the change in the inverse semi-elasticity times the estimated value of β_j for that supplier. Fig. 8(a)–(e) plots the hourly sample standard deviations of the hourly Feasible and Ideal inverse semi-elasticities each firm. Each point on the curve is the standard deviation across all days in the sample of the inverse semi-elasticity for the hour of the day on the horizontal axis. The hourly standard deviations of both the Feasible and Ideal inverse semi-elasticities tend to be higher during the high demand hours of the day. The hourly standard deviations of the feasible inverse semi-elasticities are larger than the hourly standard deviations of the ideal inverse semi-elasticities.

The hourly standard deviations of the Feasible inverse semi-elasticities are in the range of 50–100 CAD/MWh during a number of hours of the day for several of the suppliers. This implies that a one standard deviation increase in the hourly inverse elasticity for one of these hours of the day predicts an increase in the supplier's hourly offer price of 3–6 CAD/MWh for the regression coefficient estimates in Table 3. For example, for Firm A, taking the coefficient estimate in Table 3 of 0.0463 and multiplying it by 75, yields a 3.50 CAD/MWh price reduction.

This result indicates that the potential for economically significant competitiveness benefits from transmission expansions that reduce both the mean and standard deviation of the hourly inverse semi-elasticities. The standard deviations of the ideal inverse semi-elasticities are uniformly smaller than the corresponding values for the feasible inverse semi-elasticities. This result demonstrates an additional source of competitiveness benefits from transmission expansions: They reduce the frequency that each of the five large suppliers faces extremely large inverse semi-elasticities which the coefficient estimates in Table 3 imply will lead to substantially larger offer prices and substantially larger market-clearing prices.

The final step in the process of computing the counterfactual no-perceived-congestion offer curve adjusts each offer price submitted by supplier j during hour h by the difference between the feasible inverse semi-elasticity and the ideal inverse semi-elasticity times the estimated value of $\beta_{j.}$ Mathematically, if P_{jhk} is the offer price for bid quantity increment k for supplier j during hour h, then the no-perceived-congestion offer price for this bid quantity increment is

$$P^{NC}_{jhk} = P_{jhk} - \beta_j(\eta^F_{hn} - \eta^I_{hn}). \tag{12}$$

Repeating this process for all bid quantity increments yields a new vector of offer price and quantity increment pairs, Θ^{NC}. This vector is composed of the modified offer prices, P^{NC}_{jhk}, from (12) and original offer quantity increments. Let $S_h(\Theta_n{}^{NC})$ denote the modified no perceived congestion offer curve for the supplier n during hour h.

Fig. 9(a)–(c) illustrates the process used to compute $S_h(\Theta_n{}^N)$, from $S_h(\Theta_n)$, original offer curve for supplier n during hour h for hypothetical Firms A and B. The upper step function in Fig. 9 (a) and (b) are the original willingness-to-supply curves for Firms A and B. The lower step functions in the figures are the shifted down no-perceived congestion willingness-to-supply curves of Firms A and B. The upper step function in Fig. 9(c) is the original aggregate willingness-to-supply curve of Firms A and B and the lower step function is the shifted no-perceived-congestion aggregate willingness-to-supply curve for the two firms. Fig. 9 (c) demonstrates that for the same level of aggregate demand, the shifted no-perceived-congestion aggregate willingness-to-supply curve will set a lower market-clearing price, PC, than the price, P, set by original aggregate willingness-to-supply curve. This market price reduction is the source of the competitiveness benefits to electricity consumers from transmission investments.

Table 3
Coefficient estimates of β_j in Eq. (11) for supplier j.

	Coefficient estimate	Standard error
$\beta_{Firm\ A}$	0.0463	0.0017
$\beta_{Firm\ B}$	0.0293	0.0015
$\beta_{Firm\ C}$	0.0224	0.0011
$\beta_{Firm\ D}$	0.0262	0.0017
$\beta_{Firm\ E}$	0.0414	0.0013

Note: The coefficient estimate in each line of the table corresponds to a firm-level regression of Eq. (11) with day-of-sample and hour-of-day fixed effects. Standard errors are computed using the expression given in White (1980).

4. The competitiveness benefits of congestion-reducing transmission investments

This section describes the calculation of the two counterfactual no-perceived-congestion market-clearing prices. The results of computing these two prices for all hours from January 1, 2009 to July 31, 2013 are described and then several calculations are presented to demonstrate the magnitude of consumer benefits from transmission expansions that reduce the frequency and magnitude of transmission congestion. For comparison, an estimate of the change in production costs associated with the proposed transmission expansions, the measure of economic benefits used under

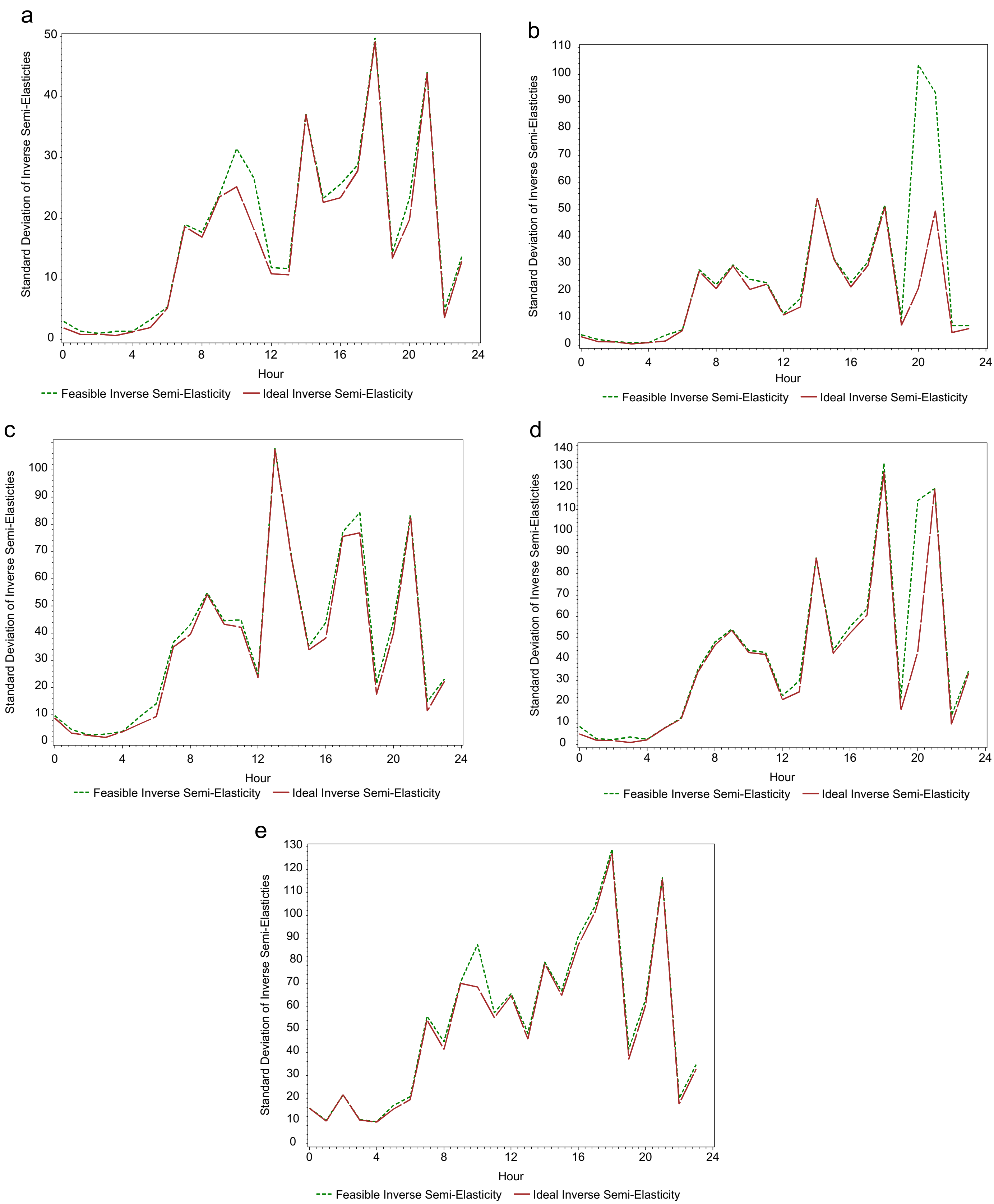

Fig. 8. (a) Standard deviation of hourly feasible and ideal inverse semi-elasticities Firm A. (b) Standard deviation of hourly feasible and ideal inverse semi-elasticities, Firm B. (c): Standard deviation of hourly feasible and ideal inverse semi-elasticities Firm C. (d): Standard deviation of hourly feasible and ideal inverse semi-elasticities Firm D. (e): Standard deviation of hourly feasible and ideal inverse semi-elasticities Firm E.

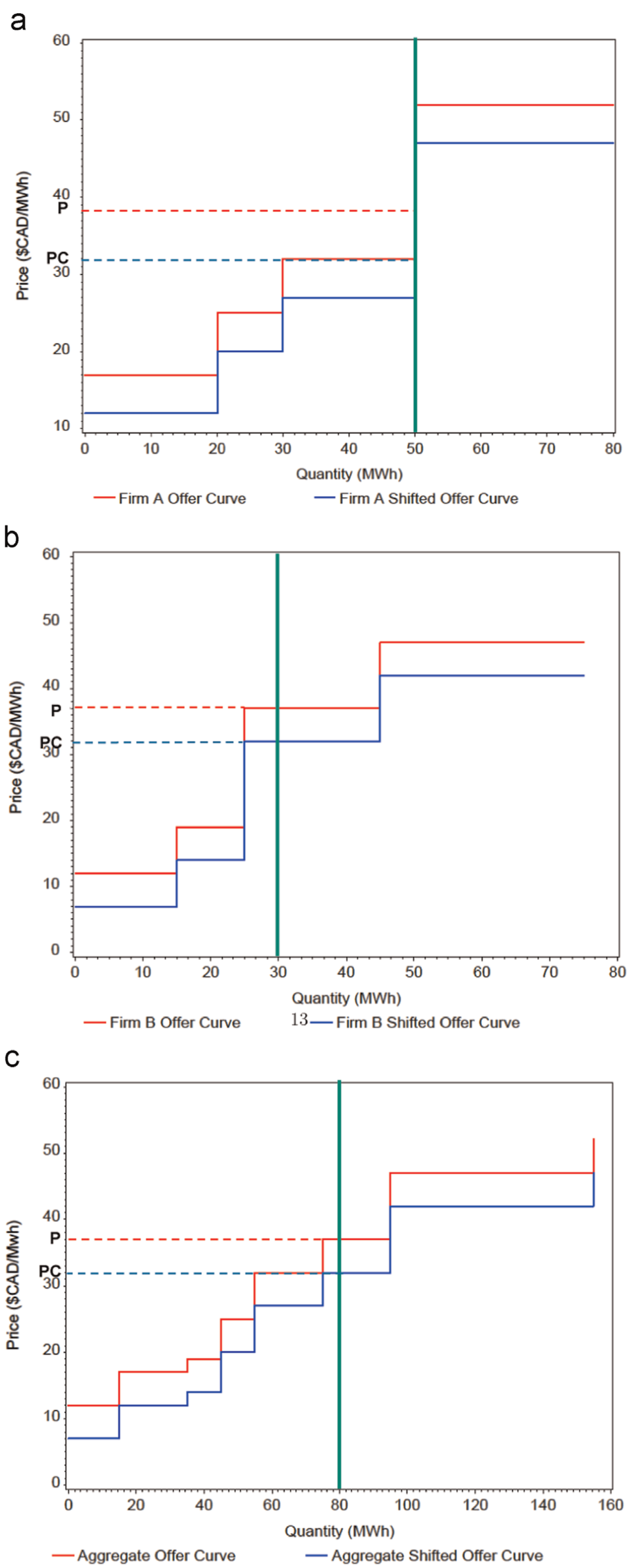

Fig. 9. (a) Actual and shifted no-congestion offer curves for Firm A. (b) Actual and shifted no-congestion offer curves for Firm B. (c) Actual and shifted no-congestion aggregate offer curves.

the former vertically-integrated regime, is also calculated.

The first counterfactual price takes an extremely conservative approach to computing the competitiveness benefits of transmission expansions. It assumes no change in what offer quantities can be accepted because of transmission constraints. The only difference from the actual market-clearing process is that the Feasible Offer Curve for the five large strategic suppliers uses the adjusted offer prices from Eq. (12). In terms of the notation of Section 3, the offer curves for the strategic suppliers are defined as $SC_h\left(\Theta_n^{NC}\right)$, the Feasible Offer Curve defined in Section 2 evaluated at Θ_n^{NC}, instead of Θ_n. This counterfactual price provides a very slack upper bound on market-clearing price that would result if all of the five large suppliers faced the Ideal Residual Demand curve instead of the Feasible Residual Demand curve because it assumes no change in the quantity of energy supplied by any generation unit in Alberta. This counterfactual market price is lower than the actual price only because the offer prices of the strategic suppliers that sell energy during the hour are lower, not because of any change in the dispatch quantity of any generation units.

To compute this counterfactual price for hour h, $SC_{nh}\left(\Theta_n^{NC}\right)$ is used for each of the five large strategic suppliers and the original feasible offer curve is used for all other suppliers. For simplicity assume that $n=1,2,..,5$ corresponds the five strategic firms and the remaining non-strategic firms are indexed $n=6,7,..,N$. The first counterfactual no-perceived transmission congestion market-clearing price for hour h is computed by solving for the smallest price such that:

$$SC_{1h}\left(p,\,\Theta_1^{NC}\right)+SC_{2h}\left(p,\,\Theta_2^{NC}\right)+\ldots+SC_{5h}\left(p,\,\Theta_5^{NC}\right)$$
$$+SC_{6h}(p,\,\Theta_6),+\ldots+SC_{Nh}(p,\,\Theta_N)=QD_h, \tag{13}$$

Because the highest offer price accepted during h could be from a non-strategic firm, even though all of the adjusted offer prices of the strategic suppliers in $\Theta_n^{NC}(n=1,2,\ldots,5)$ are less than the original offer prices in Θ_n $(n=1,2,\ldots,5)$, this market-clearing price, PC_h^F, is less than or equal to the actual market-clearing price, P_h. This weak inequality holds as a strict inequality unless the offer price of a non-strategic firm set the original market-clearing price.

To compare this Feasible Offer Curve counterfactual price-setting process to the more complicated hourly price-setting process used by the AESO that depends on the configuration of the transmission network and pattern of system demand during the hour, I also compute an estimate of the actual market-clearing price using the original Feasible Offer Curves of all suppliers. Let PP_h^F denote the smallest price that solves:

$$\begin{aligned}&SC_{1h}(p,\,\Theta_1)+SC_{2h}(p,\,\Theta_2)+\ldots\\&\quad+SC_{5h}(p,\,\Theta_5)+SC_{6h}(p,\,\Theta_6),+\ldots+SC_{Nh}(p,\,\Theta_N)\\&=QD_h,\end{aligned} \tag{14}$$

Note that original offer price and feasible offer quantities are used in the Feasible Offer Curves of all suppliers to compute the Predicted Feasible Actual market-clearing price, PP_h^F.

Fig. 10 plots the 30-day (30 days x 24 hours) moving average of the hourly market-clearing price and PP_h^F, the hourly the Predicted Feasible Actual market-clearing price. In spite of the fact that the actual hourly prices are extremely volatile, sometimes hitting the 1000 CAD/MWh offer cap, the two plots are virtually identical for all days of the sample period.[14]

The second counterfactual no-perceived congestion market-clearing price yields a lower bound on the no-perceived-

[14] The actual process used to set the hourly price in AWEM is more complex than simply crossing the hourly supply with the hourly demand. The hourly price is the average of the 60 one-minute dispatch prices. The one-minute dispatch price is the highest accepted offer price during one minute of the hour. Fig. 10 demonstrates that the simplication of the dispatch process employed here does not introduce significant errors in computing hourly prices.

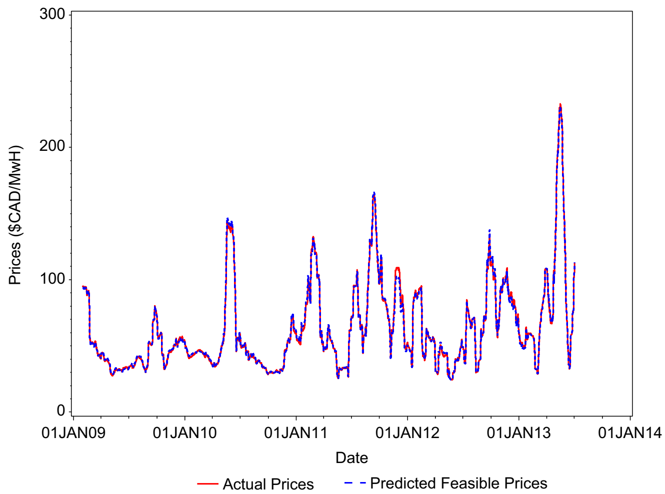

Fig. 10. Actual and predicted feasible prices, 30-day moving average.

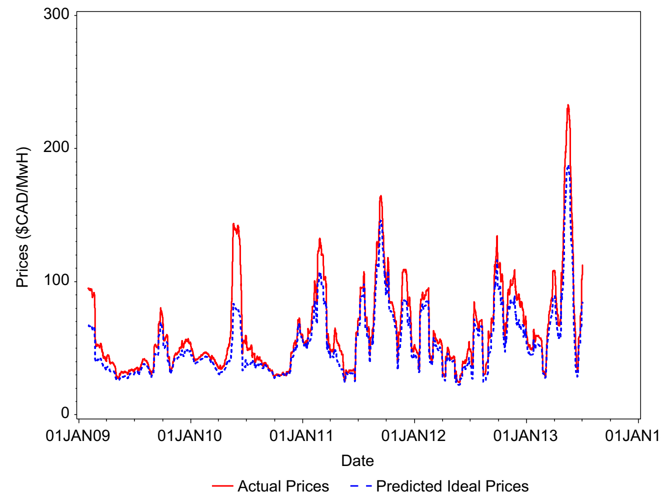

Fig. 11. Actual and predicted ideal prices, 30-day moving average.

congestion counterfactual price. It assumes that all suppliers face no transmission constraints so that the counterfactual market-clearing price is computed from the Ideal Offer Curves of the five strategic suppliers using the offer prices adjusted as described in Eq. (12) and the Ideal Offer Curves of the non-strategic suppliers. Mathematically, the counterfactual no-perceived congestion price, $PC_h{}^I$, is the smallest price that solves:

$$\begin{aligned} &S_{1h}\left(p,\ \Theta_1^{NC}\right) + S_{2h}\left(p,\ \Theta_2^{NC}\right) + \dots \\ &\quad + S_{5h}\left(p,\ \Theta_5^{NC}\right) + S_{6h}(p,\ \Theta_6), + \dots + S_{Nh}(p,\ \Theta_N) \\ &= \mathrm{QD}_h, \end{aligned} \tag{15}$$

Note that the aggregate offer curve is the sum of the Ideal Offer Curves evaluated at Θ_n^{NC} (n=1,2,..,5) for the five strategic suppliers and Θ_n (n=6,…,N) for remaining suppliers. This price is lower than $PC_h{}^F$ because it assumes that no quantity offers are prevented from selling energy because of the transmission constraints. For this reason, it provides a lower bound on the market-clearing price that would result if all strategic suppliers faced the Ideal Residual Demand curve instead of the Feasible Residual Demand curve but kept the same fixed-price forward contract obligations.

Following the analogous logic to computing the Predicted Feasible market-clearing price, a Predicted Ideal market-clearing price can be computed by constructing an aggregate supply curve from the sum of the Ideal Offer Curve for all suppliers. Mathematically, the Predicted Ideal market-clearing price, $\mathrm{PP}_h{}^I$, is the smallest price that solves:

$$\begin{aligned} &S_{1h}(p,\ \Theta_1) + S_{2h}(p,\ \Theta_2) + \dots \\ &\quad + S_{5h}(p,\ \Theta_5) + S_{6h}(p,\ \Theta_6), + \dots S_{Nh}(p,\ \Theta_N) \\ &= \ \mathrm{QD}_h, \end{aligned} \tag{16}$$

This price should be less than or equal to the actual market-clearing price because it assumes that the Ideal Offer Curves are used for all suppliers, including the five strategic suppliers.

Fig. 11 plots the 30-day moving average of the hourly price and the hourly Predicted Ideal price. Although the 30-day moving average of the Predicted Ideal prices follows the same general pattern as the 30-day moving average of actual prices, they are typically lower and less volatile than the actual prices. Particularly, during the high-priced periods of the sample, $PP_h{}^I$ is significantly less than the actual market-clearing price and the Predicted Feasible Actual market-clearing price. This result suggests that even without a change in a supplier's offer behavior, increasing the amount of transmission capacity to reduce the number and total volume of offer quantities that cannot sell energy because of transmission constraints has significant consumer benefits in terms of lower average wholesale prices and less volatile wholesale prices.

For each of the two counterfactual prices, I compute two measures of the competitiveness benefits of transmission investments that reduce the frequency of congestion. The first is the difference between the market price and the counterfactual price times the total demand in the AESO. The second is a relative measure, the predicted reduction in wholesale market revenues as a percentage of predicted wholesale market revenues, the market-clearing price times the total demand in the AESO during hour h, QD_h. In terms of our previously defined notation, the first two hourly measures are as follows:

$$\Delta R_h^F = \left(P_h – \mathrm{PC}_h^F\right)\mathrm{QD}_h \text{ and } \Delta R_h^I = \left(P_h – \mathrm{PC}_h^I\right)\mathrm{QD}_h, \tag{17}$$

which are the difference in wholesale market revenues from consumers paying the counterfactual Feasible Market Price and the difference in wholesale market revenues from consumers paying the counterfactual Ideal Market Price. The second two measures are the ratio of the difference in wholesale market revenues over some time horizon divided by actual wholesale market revenues over that same time horizon. Let H equal the number of hours in that time horizon, then

$$\begin{aligned} \Delta RR_h{}^F &= 100 * \frac{\sum_{h=1}^H \left(\mathrm{P}_h \ - \ \mathrm{PC}_h^F\right)\mathrm{QD}_h}{\sum_{h=1}^H \mathrm{P}_h * \mathrm{QD}_h} \text{ and} \\ \Delta RR_h^I &= 100 * \frac{\sum_{h=1}^H \left(\mathrm{P}_h \ - \ \mathrm{PC}_h^I\right)\mathrm{QD}_h}{\sum_{h=1}^H \mathrm{P}_h * \mathrm{QD}_h} \end{aligned} \tag{18}$$

which are the changes in wholesale energy revenues over horizon H as a percent of actual wholesale revenues over horizon H for both the Feasible and Ideal counterfactual prices.

Table 4 lists the annual average of the hourly wholesale revenue changes for the Ideal counterfactual prices (column 2) and Feasible counterfactual prices (column 3) for 2009–2012 and the first seven month of 2013. The last row lists the average hourly values for the entire sample period. Fourth column of the table lists average hourly wholesale market revenues for each year and for the entire sample. The fifth column shows the annual average hourly wholesale revenue difference using the Ideal Counterfactual price as a percentage of annual average hourly wholesale market revenues. The last column shows the annual average

Table 4
Annual and sample average hourly revenue differences for ideal and feasible counterfactual prices in CAD and as a percentage of annual wholesale market revenues.

Year	Average hourly ideal price revenue difference (CAD)	Average hourly feasible price revenue difference (CAD)	Average hourly wholesale market revenues (CAD)	Ideal revenue difference as a percent of wholesale revenues	Feasible price revenue difference as a percent of wholesale revenues
2009	57177.04	1002.96	400114.08	14.29	0.25
2010	66244.95	1282.42	431907.17	15.34	0.30
2011	67364.19	4367.33	674624.51	9.99	0.65
2012	80120.13	3332.33	581075.83	13.79	0.57
2013*	147538.14	4003.73	788954.10	18.70	0.51
Overall	77857.41	2688.66	555882.46	14.01	0.48

* Note that 2013 amounts are for January 1–July 31.

hourly wholesale revenue difference using the Feasible Counterfactual Price as a percentage of annual average hourly wholesale market revenues.

Fig. 12(a) and (b) plots the monthly average values of the hourly wholesale revenue changes for the Feasible and Ideal Counterfactual Prices. The average monthly demand served in the AESO is also plotted in each figure. The average monthly wholesale revenue changes using the Feasible Counterfactual Price shown in Fig. 12(a) finds economically significant competitiveness benefits from suppliers submitting offer prices under the expectation of no congestion but actually facing the same amount of congestion (no change in the hourly output of all generation units) as actually occurred during that hour. Although the average hourly revenue change over the sample is 2688.66 CAD, during one month it exceeds 12,500 CAD. Comparing the pattern of the monthly average demand in the AWEM to the monthly average values of the Feasible Counterfactual Price wholesale revenue difference shows an increasing relationship between the two monthly values.

Fig. 12(b) finds substantially larger revenue changes associated with the strategic suppliers submitting offer prices under the expectation of no congestion and the realization that there is actually no congestion, the Ideal Counterfactual Price hourly wholesale revenue difference. The sample average hourly wholesale revenue difference using the Ideal Counterfactual Price is 77,857 CAD. There is even a month when the average hourly wholesale revenue difference with the Ideal Counterfactual price is greater than 400,000 CAD. There appears to be a positive correlation between the monthly average value of this revenue difference and the monthly average value of demand in the AWEM.

The pattern of the monthly value of the wholesale revenue differences using the Feasible Counterfactual price as a percentage of actual monthly wholesale market revenues in Fig. 13 (a) replicates the pattern of the monthly wholesale revenue differences in Fig. 12(a). For the entire sample the Feasible Counterfactual price wholesale revenue difference is 0.48% of total wholesale energy revenues. However, during certain months, this percentage is substantially higher. In fact, it is more than 1.6% of monthly wholesale energy revenues during one month of the sample.

For the entire sample, the Ideal Counterfactual price wholesale revenue difference is 14% of total wholesale energy revenues. As shown in Fig. 13(b), during certain months, this percentage is substantially higher, and in one month it is more than 36% of actual wholesale market revenues. Although for most of the months this percentage is below 20%, it never fall below 5%, indicating that during all months of the sample period there are substantial competitiveness benefits from suppliers expecting there to be no

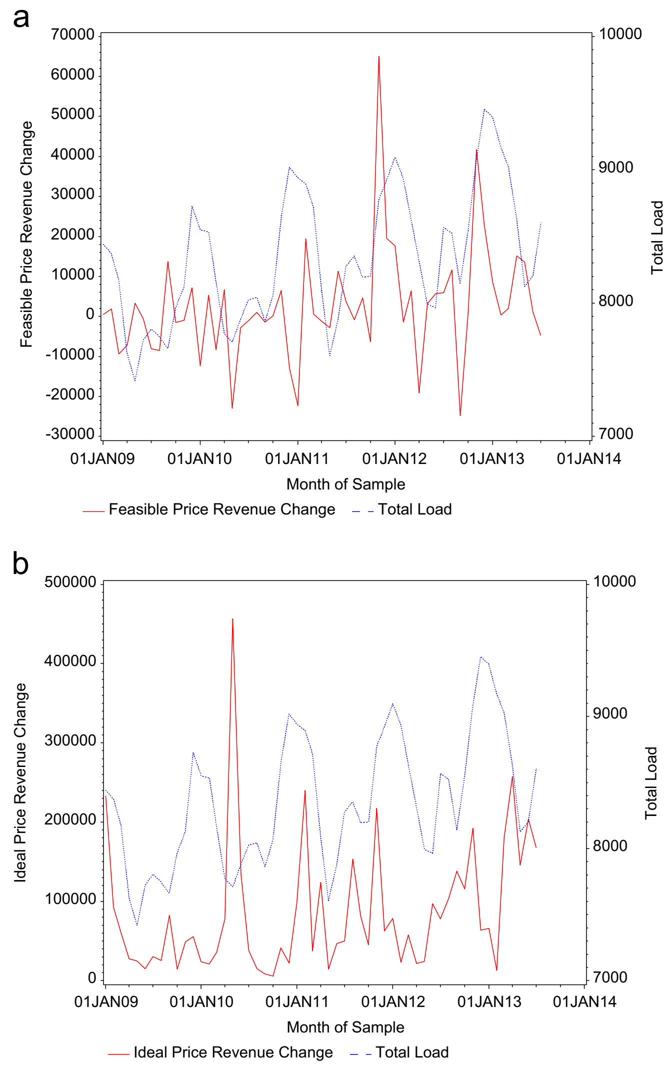

Fig. 12. (a) Monthly average wholesale revenue change with feasible price and monthly average demand. (b) Monthly average wholesale revenue change with ideal price and monthly average demand.

transmission constraints that prevent quantity increments offered by them and their competitors from selling energy and this expectation in fact turns out to be case.

It is also possible to estimate the dispatch costs savings associated with each of these hourly counterfactual market outcomes. Using information on the heat rate (the gigajoules of heat energy from the unit's input fossil fuel required to product one MWh of electricity) for each generation unit in the AWEM, daily fuel fossil prices in CAD per gigajoule (GJ), and the estimated variable operating and maintenance (O&M) cost of each generation unit obtained from the AESO, an estimate of the marginal cost of each fossil fuel generation unit in AWEM can be computed. The estimated marginal cost of a fossil fuel generation unit is set equal the heat rate in GJ/MWh times the price of the fossil fuel in CAD/GJ plus the variable O&M cost in CAD/MWh. The variable O&M cost was assumed to be 3 CAD/MWh for natural gas units and 5 CAD/MWh for coal units. renewable resources were assumed to have the following marginal costs: biomass, 4 CAD/MWh; wind 1 CAD/MWh, and hydroelectric 2 CAD/MWh. Multiplying the hourly output in MWh of each unit times this marginal cost and summing across all units producing during the hour yields an estimate of the total production costs associated with serving demand in that hour.

This same process can be followed for both the Feasible and

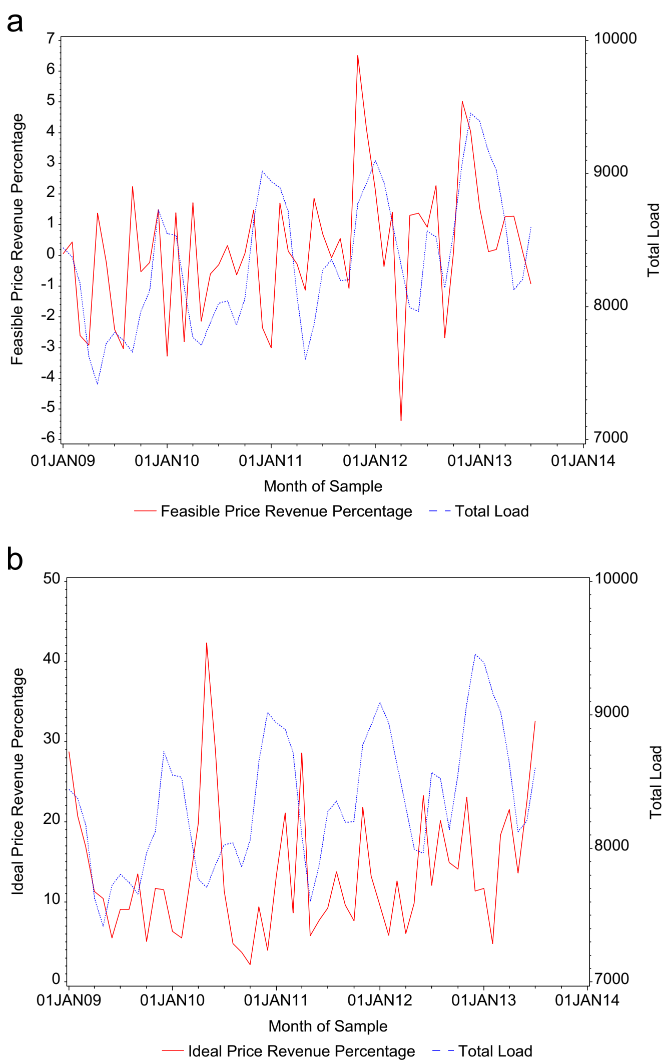

Fig. 13. (a) Monthly wholesale revenue change with feasible price as a percentage of actual monthly wholesale revenues and monthly average demand. (b) Monthly wholesale revenue change with ideal price as a percentage of actual monthly wholesale revenues and monthly average demand.

Ideal counterfactual market outcome. Each hourly counterfactual market outcome yields a output level for each generation unit dispatched to meet the hourly demand. For the case of the Feasible counterfactual market outcome, the same generation units are dispatched at the same level of output as under the actual dispatch because the location, level, and incidence transmission congestion is assumed to be same as under the actual dispatch. This implies that the Feasible counterfactual total production costs associated with serving demand is the same as the actual production cost associated with serving demand during each hour of the sample.

In contrast, for the Ideal counterfactual market outcome, the total production costs associated with serving demand should be lower, because more output from low cost units can be accepted to serve demand because there is assumed to be no transmission congestion under the Ideal market outcome. Repeating the above process using these same generation unit level marginal cost figures yields estimates of the hourly cost of meeting demand in that hour associated with the Ideal counterfactual market outcome.

Table 5 repeats the calculations in Table 4 using actual production costs and Ideal counterfactual operating costs. The third column of the table gives the annual hourly average value of actual wholesale energy production costs for each year of the sample. The second column given the annual hourly average value of the difference between actual production costs during the hour and the production costs during the hour under the Ideal counterfactual market outcome.[15] The fourth column gives the difference in column 2 as a percentage of annual average hourly wholesale energy production costs. Table 5 demonstrates that the upper bound on the production cost savings associated with eliminating transmission congestion is slightly more than one-half of a percent of total wholesale energy production costs over the sample period. This result demonstrates that failing to incorporate competitiveness benefits into the transmission planning process in wholesale markets would prevent many transmission expansions with consumer expected benefits in excess of their expected costs from being built.

Table 5
Annual and sample average hourly production cost differences for ideal counterfactual dispatch in CAD and as a percentage of annual wholesale energy costs.

Year	Average hourly counterfactual ideal dispatch cost difference (CAD)	Average hourly wholesale energy costs (CAD)	Ideal counterfactual dispatch cost difference as a percent of wholesale costs
2009	1482.71	129592.85	1.14
2010	941.03	138921.42	0.68
2011	262.73	134095.85	0.20
2012	386.01	117373.21	0.33
2013*	414.25	137794.93	0.30
Overall	722.64	130973.32	0.55

* Note that 2013 amounts are for January 1–July 31.

5. Conclusions and policy implications

These empirical results demonstrate economically sizeable competitiveness benefits from facing strategic suppliers with residual demand curves that reflect little likelihood that transmission constraints will limit the competition they face during the hour. Even for the counterfactual that assumes these expectations do not turn out to be the case, because strategic suppliers with these expectations about the extent of competition that they face are predicted to submit lower offer prices, the resulting market-clearing prices, even with the same amount of transmission congestion as actually occurred, will be lower. These Feasible Counterfactual Offer Curve market-clearing prices imply sizeable average wholesale revenue differences, an average of 2687 CAD per hour. Over the sample period, the total wholesale revenue difference from the five largest strategic suppliers in AWEM expecting that none of the quantity increments of their competitors will be unable to supply energy because of transmission constraints is more than 107 million CAD, even if there were no change in the actual realized transmission congestion.

If these expectations of no congestion by the strategic suppliers actually hold and no suppliers are actually prevented from selling energy because of transmission constraints and the Ideal Counterfactual Offer market-clearing prices are the relevant price paid by electricity consumers, the total wholesale cost savings for the sample period is more than 3 billion CAD. Clearly, this amount of wholesale cost savings over a 4-year and 7-month period could fund a substantial amount of transmission expansions.

In contrast, the maximum wholesale production cost savings over the sample period, which is the difference between actual

[15] The generation units dispatched under the counterfactual feasible market outcome are the same as those dispatched under the actual market outcome, so the production cost difference is identically equal to zero for each hour for the actual market outcome minus counterfactual Feasible market outcome.

production costs and those associated with the Ideal dispatch (that assumes no transmission congestion) averages 722.64 CAD per hour. This amounts to 29 million CAD in production cost savings from no transmission congestion over the 4-year and 7-month period, or slightly more than 0.5% of total production costs over that time period.

Taken together, these empirical results imply that failing to account for the competitiveness benefits of transmission expansions in wholesale electricity markets and instead relying on the economic benefits measure used under the former vertically integrated monopoly regime of the change in total production costs, will prevent many transmission expansions with positive net economic benefits to electricity consumers from being built. This argument is particularly persuasive for a market like the AESO given the shares of generation capacity controlled by the five strategic suppliers and the dominant share that coal and natural gas-fired generation capacity plays in the electricity supply mix. The extremely steep offer curves that suppliers submit, particularly during periods when there is likely to be transmission congestion, argues in favor of a transmission policy that accounts for these competitiveness benefits. A surprising number of markets in the United States and around the world share similar structural features to the AWEM, which argues for incorporating competitiveness benefits into the transmission planning processes in all bid-based wholesale electricity markets.

These results also support the view that planning and constructing the transmission network in Alberta in a forward-looking manner to realize these competitiveness benefits can yield sizeable net benefits to electricity consumers in the province as demonstrated by both the Feasible and Ideal Counterfactual price wholesale market revenue differences.

Finally, it is important to emphasize that a potentially sizeable source of additional competitiveness benefits was not accounted for in this analysis. Specifically, the incentive for a supplier to change its fixed-price forward contract obligations in response to the reduced number of opportunities to exercise unilateral market power because of the increased competition it faces because of the significantly reduced frequency and magnitude of transmission congestion is not accounted for. Such an analysis would require information on the fixed-price forward market obligations of the five largest strategic suppliers in the AWEM. This data is currently considered confidential by market participants and is not available to the AESO. However, given the current concentration of generation ownership in the AWEM and the structure of offer curves submitted to the AESO during the sample period, this forward contracting competitiveness benefit from a transmission planning and construction policy that limits the frequency and magnitude of transmission congestion is likely to be economically significant.

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