Report on the Performance of the California ISO's Local Market Power Mitigation Mechanism During the First Year

by

Frank A. Wolak, Chairman
James Bushnell, Member
Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO

May 28, 2010

Submitted to the Federal Energy Regulatory Commission

Summary

The Federal Energy Regulatory Commission (the Commission) asked the Market Surveillance Committee of the California Independent System Operator (ISO) to prepare a report on the performance of the ISO's local market power mitigation (LMPM) mechanism during the first year of operation under the new market design and to suggest possible to changes that would improve wholesale market performance. We first describe the role of a LMPM mechanism in a bid-based, short-term wholesale electricity market and then analyze the potential for both over-mitigation and under-mitigation of generation units under the California ISO's current local market power mitigation mechanism. We then review the performance of the California ISO's existing local market power mitigation mechanism over the past year. We believe that the unique circumstances in the California economy and electricity supply industry over the past year, make imprudent to draw any conclusions about the properties of the California ISO's LMPM mechanism from these market outcomes. We then summarize stakeholder concerns and our concerns with the California ISO's current LMPM mechanism and suggest a possible alternative to the current LMPM mechanism that may address many these concerns.

1. Introduction

The Federal Energy Regulatory Commission (the Commission) asked the Market Surveillance Committee of the California Independent System Operator (ISO) to prepare a report on the performance of the ISO's local market power mitigation (LMPM) mechanism during the first year of operation under the new market design and to suggest possible to changes that would improve wholesale market performance.[1] This report responds to that request. We first present a framework that clarifies the role of a LMPM mechanism in a bid-based, short-term wholesale electricity market. This framework is then used to analyze the potential for over-mitigation of generation units under the California ISO's current local market power mitigation mechanism.

We then review the performance of the California ISO's existing local market power mitigation mechanism over the past year. Because of the unique circumstances in the California economy and electricity supply industry over the past year, it would be premature to draw any conclusions about the properties of the California ISO's LMPM mechanism from these market outcomes.

The next section summarizes stakeholder concerns and our concerns with the California ISO's current LMPM mechanism. We then suggest a possible alternative to the current LMPM mechanism that may address many these concerns. We then describe the possible analyses of market outcomes to assess the performance of the current LMPM mechanism and the viability of our alternative approach.

---

[1]:*Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, P 1032 (2006).

2. The Role of a Local Market Power Mitigation Mechanism

The Federal Power Act (FPA) requires the Commission to ensure that wholesale electricity prices are just and reasonable. Cost-of-service prices are an example of an accepted definition of just and reasonable. Consequently, all suppliers are able to sell at cost-based wholesale prices under Commission rules.

The Commission allows suppliers to substitute market-based prices for cost-based prices and still satisfy the just and reasonable price standard of the FPA if the supplier can demonstrate that it does not possess market power or has adequately mitigated it. This substitution is possible because the Commission has ruled that the FPA just and reasonable price standard implies that prices that do not reflect the exercise of market power are just and reasonable.

This standard can be challenging to satisfy when transmission constraints prevent enough independent suppliers from competing for sales of services at specific locations in the transmission network. These constraints bestow ``local market power'' on suppliers at these locations, and it is unreasonable to expect competitive behavior from them under uncompetitive market conditions. A LMPM mechanism plays a critical role in ensuring the competitiveness of a wholesale electricity market under these system conditions. It provides necessary protection against the exercise of market power by a supplier in an organized wholesale market that can thereby allow the seller to obtain market-based pricing authority.

2.1. Attributes of LMPM Mechanisms

Market power mitigation mechanisms have three basic characteristics. The first is to determine when a supplier possesses sufficient market power to be worthy of mitigation. The second is what to do with the supplier's offers when they are deemed to require mitigation. The third is what that supplier and all other suppliers are paid when that supplier's offer is subject to mitigation.

2.1.1. Determination of Eligibility for Mitigation

The California ISO employs a competitive path assessment (CPA) method as the foundation of its process for determining when a specific unit might be subject to mitigation. In advance, the ISO designates specific transmission paths as either competitive or uncompetitive in a process described below. The general approach is only to mitigate bids generation units needed to relieve congestion on uncompetitive paths.

As part of market operation, the CPA method computes a market price and dispatch level for the generation unit by first running the market software only imposing the competitive transmission constraints and then by imposing all transmission constraints. Any generation unit that has a higher output in the all-constraints (AC) run than in the competitive constraints (CC) run is eligible to have its offer curve mitigated.

2.1.2. Offer Price Mitigation Levels

There is a general consensus across US ISOs/RTOs that if a supplier's offer price is mitigated then its actual offer price should be replaced with the market operator's estimate of the price that supplier would offer if it faced significant competition. Under the California ISO's market power mitigation mechanism, this mitigated offer curve is always greater than or equal to the supplier's default energy bid (DEB) bid curve, which is equal to the ISO's estimate of its variable cost plus a 10 percent adder.[2]

[2] Appendix A.4 of the "2009 Annual Report on Market Issues and Performance" (April 2010) prepared by the Department of Market Monitoring provides a detailed example of the construction of a mitigated offer curve.

A unit that has its output increased in the AC run can have its offer price mitigated to the locational price for that generation unit in the competitive constraints run, as long as that price lies above the unit's default energy bid. Otherwise, the mitigated bid curve is equal to the unit's DEB. This mechanism for computing the supplier's mitigated bid curve (that enters into the final price-setting process) ensures that it always lies above or is equal to the generation unit owner's DEB.[3]

A supplier that faces substantial competition for its output believes that it is unable to influence the market price through its unilateral actions because a number of other independent firms stand willing to supply the market if this firm raises its offer price. A supplier that believes it is unable to influence the market price through its unilateral actions will find it expected profit-maximizing to submit its variable cost curve as its willingness-to-supply curve, regardless of the actions of its competitors. Put simply, a seller with no market power would want to be supplying power as long as the price exceeds its incremental cost of supply.[4]

A natural concern is the ability of the ISO to measure the incremental cost of supply, particularly given the many potentially complex operating constraints a generator must deal with. However, because generation units dispatched by the California ISO are guaranteed recovery of their start-up and no-load costs, there is no need for a supplier to submit an offer for its energy above its variable cost in an attempt to recover these costs through higher market-

[3] From July 2009 onwards, generation unit owners had the option to have their default energy bids calculated using an LMP-based approach. As described in Section 4.4.3 of the "2009 Annual Report on Market Issues and Performance," this option was initially popular with generation unit owners, but was ultimately abandoned by most unit owners because the resulting DEBs turned out to be less than the DEBs computed under the cost-based option.

[4] We note that there are circumstances in which opportunity costs, in the form of foregone revenue from other markets or other times, are the basis for the relevant incremental costs for a generating unit, rather than fuel and variable O&M. This is most obviously the case with hydro units or emissions limited units. Such opportunity costs can be an economically legitimate basis of default energy bids, but only if the foregone revenue is based on prices that reflect competitive market conditions.

clearing prices. Finally, in the presence of appropriate scarcity pricing mechanisms, neither is it necessary for a supplier to submit price offers above its marginal cost to recover capital and other fixed costs, even in the case of peaking facilities. For the purposes of this discussion, we assume that the mechanism for start-up and minimum load cost recovery, scarcity pricing, and resource adequacy function as intended.

Suppliers that are deemed to possess local market power by the California ISO's CPA test are allowed to submit an offer curve that exceeds or equals their variable cost plus a 10 percent adder. These facts imply that the owner of a mitigated generation unit is permitted to submit an offer curve that is likely higher than the curve the owner would find expected profit-maximizing to submit if it did not possess unilateral market power. Consequently, one cannot argue that a unit owner is being over-mitigated by the California ISO's current LMPM mechanism because, when mitigated, the unit owner is allowed to submit an offer price that is at least 10 percent above its variable cost of producing electricity. Moreover, because system conditions are such that this supplier possesses local market power worthy of mitigation, at least of portion of its mitigated offer curve, which exceeds its variable cost of production, is virtually guaranteed to be accepted to provide energy by the market operator in the final dispatch and pricing run.

3. Concerns with Over-Mitigation and Under-Mitigation

One of the key questions to ask in evaluating a market-power mitigation mechanism is whether its effectiveness in enhancing competition produces benefits that exceed the potential costs and burdens of additional regulation. Because local market power is an extreme form of market power, methods for mitigating it are necessarily stronger and are likely to be applied more frequently than would be methods for dealing with market power over much larger markets.

Some have raised concerns over whether such methods might lead to ``over-mitigation'' of suppliers. The concept of over-mitigation is not well defined, but we take the term to mean the following. Over mitigation could arise if a regulation causes the prices earned by a unit or units to be reduced *below* fully competitive levels. The frequency with which mitigation is applied is sometimes used as a criterion for defining over-mitigation, however we wish to emphasize that the frequency of mitigation is not the central concern. It is rather the level to which bids are set and the subsequent prices earned by suppliers that are the most important factors. As long as mitigated units are earning prices at or above completive levels, then the frequency with which this happens is of much less import.

The California ISO's current market LMPM mechanism constructs the cost-based DEB for a generation unit owner in a manner that yields market prices that are generous to all suppliers. There are three reasons why this is the case. First, the process used to compute a mitigated supplier's variable cost is based on technical specifications and cost information submitted to the California ISO by the market participant. The credibility of this information is subsequently checked by the Department of Market Monitoring (DMM). However, because generation unit owners are likely to have better information than the DMM about the technical specifications of their generation units and the economic opportunities to purchase input fuels and other factors of production for these units, the variable cost estimates that result from this process are likely, if anything, to be upward biased relative to the unit's minimum variable cost of production, i.e., generation unit owners are not likely to understate the variable costs of their units. Second, a 10 percent adder is applied to this upward biased variable cost estimate.

Finally, this variable cost estimate plus a 10 percent adder is then used to set nodal prices throughout California in the final AC run. Consequently, if the procedure used by the ISO to compute a generation unit owner's variable cost of production includes all relevant costs, it is hard to argue that ISO's LMPM mechanism over-mitigates generation units.

Under the current LMPM mechanism, the ISO's estimate of the supplier's variable cost plus a 10 percent adder is a lower bound on the price that a mitigated supplier receives for selling its output. If there are higher-priced offers that must be taken to serve demand, or other operating or local scarcity constraints that increasing the cost of serving load near a mitigated generation unit, the mitigated unit will be paid a nodal price that is substantially larger than its mitigated offer.

This mitigated offer can also raise the price that other nearby suppliers receive relative to the case that the mitigated supplier submitted a price offer equal to its minimum variable cost of production. Mitigated offers from frequently mitigated units (FMUs) are even more likely to raise nearby nodal prices because the market rules allow these units to have an offer adder substantially higher than 10 percent of the unit's estimated variable cost and these mitigated offers can impact the LMP at that unit's location and nearby locations.

Further evidence that the California ISO's current LMPM mechanism does not over-mitigate generation units is presented in Figures 4.13 and 4.14 from the "2009 Annual Report on Market Issues and Performance." These figures show that LMP-based DEBs for natural gas-fired generation units in California were lower than the cost-based DEBs. The LMP-based DEBs are calculated by computing the average of the lowest quartile of LMPs for that unit's location for all time periods in which the unit was dispatched over the previous 90 days. Different LMP-based DEBs are computed for peak and off-peak periods of the day and for the day-ahead and real-time markets, for a total of four LMP-based DEBs. In all four cases, the average cost-based DEB exceeds the average LMP-based DEB.

This result would occur if natural gas generation unit owners submitted offer prices below their cost-based DEB during the hours when their units are dispatched and the resulting LMPs enter the computation of their cost-based DEBs. These hours are also likely to be when these generation unit owners face sufficient competition for their output to submit offer curves close to their minimum variable cost of production. Therefore, the results in Figures 4.13 and 4.14 from the "2009 Annual Report on Market Issues and Performance" are consistent with these suppliers submitting offer curves below their cost-based DEBs during the hours when they have no ability to exercise unilateral market power.

If the goal of California ISO's LMPM mechanism is to ensure that consumers pay just and reasonable prices for wholesale power by preventing suppliers from exercising unilateral market power, then requiring a supplier to submit mitigated offer prices that are at least as great than its correctly computed cost-based DEB implies that the LMPM mechanism cannot over-mitigate a supplier.

It is important to emphasize that a supplier's mitigated offer price need not be the market-clearing price earned by mitigated units. Crucially, it is the *offers* of suppliers that are directly mitigated and not the prices earned by those suppliers. Suppliers deemed to have local market power and made subject to mitigation often earn prices well above their mitigated offer levels.

3.1. Revenue Adequacy and Over-Mitigation

It is also important to emphasize that the inability of a supplier sometimes subject to offer mitigation to earn sufficient revenues from merely selling energy to recover its fixed costs is not evidence that the local market power mitigation mechanism is unjust and unreasonable. There are many revenue sources available to generation units in the California market besides those earned from sales in the day-ahead and real-time energy markets. A supplier can also receive payment from the Resource Adequacy process or ancillary services payments from the Regulation, Spinning Reserve, or Non-Spinning Reserve markets. Suppliers can also receive payments from sales of fixed-price forward contracts for energy and ancillary services. Simply looking at the price of energy in the California ISO"s day-ahead or real-time market and saying that a supplier is not receiving a just and reasonable price because it cannot recover its fixed costs from short-term energy prices alone ignores these other revenue sources.

Even if the prices a supplier receives for all the products that it sells in the California market are the result of competitive market mechanisms, these prices do not guarantee fixed cost recovery for all generation units. Only the productive capacity necessary to serve demand is likely to receive fixed cost recovery in a competitive market. Because future demand is uncertain, some of the new productive capacity built may not receive fixed cost recovery. The RA process attempts to limit the likelihood of this outcome by requiring retailers and larger customers to purchase in advance of the date that the new generation capacity is required to be operating. Nevertheless, demand growth is sometimes slower than expected so that short-term prices for energy and ancillary services may be below the level necessary for full fixed-cost recovery by some units, even if they sold RA capacity. This outcome is not an indication that the LMPM mechanism is over-mitigating the supplier, only that demand growth was not as large as expected or the amount of new entry of generation capacity was larger than expected.

If some generation units are not recovering their fixed costs from sales in the California ISO day-ahead and real-time energy markets during the limited number of times that mitigation is required, this does not imply that the LMPM mechanism is over-mitigating suppliers. If the market power mitigation mechanism approximates supplier behavior when competitive conditions exist, then offer mitigation cannot result in unjust and unreasonable market outcomes. As explained earlier, the current LMPM mechanism approximates competitive behavior by suppliers when mitigation occurs in a manner that biases market-clearing prices upward, so it cannot result in prices that are too low to be just and reasonable relative to the competitive market benchmark implicit in the FPA's just and reasonable price standard.

Because there are many revenue sources available to generation units, focusing on a generation unit owner's revenues solely from California ISO's energy market in isolation from other markets ignores the reality that electricity consumers must pay all of these prices to procure their wholesale electricity needs. Consistent with the FPA's just and reasonable price mandate for consumers, the prices for all of these products—fixed-price long-term energy and ancillary services contracts, RA capacity, short-term energy and ancillary services—should be the result of competitive market outcomes, including the times that suppliers' offers are mitigated to approximate competitive behavior through a local market power mitigation mechanism.

If the markets for all of these products produce competitive market outcomes either because there is substantial competition or because a local market power mitigation mechanism that approximates competitive behavior when substantial competition does not exist, then it is very likely that all suppliers necessary to serve demand will receive sufficient compensation to remain financially viable. The RA market is designed to procure sufficient capacity in advance to ensure that the future demand for energy and ancillary services can be met even if demand growth is higher than expected.

Finally, it is important to emphasize that the California market rules also allow a generation unit owner to submit a price-based offer that is below its DEB. In this case, even if the supplier is required to supply more energy in the AC run than in the CC run, its mitigated bid curve will equal its actual offer curve. Unit owners always have the freedom to submit a price-based bid below their DEB to escape price mitigation. Because the unit's correctly computed cost-based DEB is above the price-based offer that an owner facing sufficient competition would find unilaterally expected profit-maximizing to submit, it is difficult to argue that the California ISO's existing LMPM mechanism over-mitigate generation units. The frequency that a supplier's AC run output exceeds its CC run output is irrelevant to the question of whether a supplier is over-mitigated or not, because the supplier is always free to submit the offer that it would find profit-maximizing if it faced sufficient competition, and thereby escape offer price mitigation.

4. Review of Performance of Current LMPM Mechanism

As noted in the "2009 Annual Report on Market Issues and Performance" the LMPM mechanism was triggered very infrequently in the day-ahead market and only slightly more frequently in the real-time market. During each month of 2009, an average of between 1 and 3 units per hour were subject to mitigation in the day-ahead market. During each month of 2009, an average of between 2 and 7 units were subject to mitigation in the real-time market.

Consistent with the market rule described above which allows suppliers to submit market-based bid curves below their DEB, approximately 80 percent of the units subject to mitigation in the day-ahead market (their CC run output was less than their AC run output), had their bid curves lowered a result of mitigation. Recall that even though a generation unit may be eligible for offer price mitigation, if their offer curve is below their DEB curve, then there is no mitigation. In the case of the real-time market, roughly half of the units subject to mitigation had their price offers lowered as a result of mitigation during 2009.

The additional amount of energy dispatched in each hour of the day-ahead market as a result of the mitigation, computed as described in Appendix A.4 of the "2009 Annual Report on Market Issues and Performance" was less than 100 MW during all months of 2009 except September, when the average hourly amount was slightly less than 140 MW. These amounts should be contrasted with the average hourly load during 2009 of 26, 324 MW and the peak demand during 2009 of 46,042 MW.

A number of factors contributed to the small amount of bid mitigation that occurred in day-ahead and real-time markets during 2009. First, the average hourly load in California fell by more than 4% from 2008 to 2009 and the peak demand in 2009 was lower than the peak demand in 2008. As shown in Figure 2.3 of the "2009 Annual Report on Market Issues and Performance," the load duration curve for 2009 was noticeably lower than the load duration curves for 2006, 2007 and 2008.

The frequency and magnitude of transmission congestion on the interties into the California ISO control area were significantly lower in 2008 relative to 2009, as well. Day-ahead congestion within in the ISO control area was also relatively minor. The percentage of hours congested on major internal constraints was typically less than 3% percent of the hours of the year, according to Figure 5.3 of the "2009 Annual Report on Market Issues and Performance." This frequency of congestion has a very little impact on prices at the different load aggregation points (LAPs) within the California ISO control area. Congestion occurred more frequently in the real-time market, but a non-trivial amount of this congestion could attributed to factors related to the start-up of the new market design. Although congestion in the real-time market could result in significant locational price differences, the small amount of energy transacted these prices implies very small overall wholesale energy price impacts from congestion in the real-time market during 2009.

All of these factors point to much lower-stress system conditions throughout 2009 relative to previous years, due in large part to a low level of economic activity and mild weather conditions. For this reason, any conclusions drawn about the performance of the current LMPM mechanism from 2009 load conditions are unlikely to be representive of load conditions with a higher level of economic activity in California and more severe summer weather conditions.

5. MSC and Stakeholder Concerns with Existing LMPM Mechanism

The California ISO's existing LMPM mechanism has been the topic of discussion at several recent MSC meetings, most recently the March 19, 2010 meeting. The major concern of generation unit owners with the existing LMPM mechanism is that small number of transmission paths that have been designated as competitive in the current LMPM mechanism. This conservative approach is necessitated by the prospective nature of the current LMPM mechanism, where the competitiveness of transmission paths is assessed on a seasonable basis in advance of actual market operation and maintained for the entire season, regardless of actual system conditions.

Under the current California ISO tariff, candidate transmission paths that could be deemed competitive are only those paths with more than 500 hours of managed congestion over the past 12 months. The DMM then simulates market outcomes under a set of pre-specified system conditions and on this basis determines whether to designate the transmission path as non-competitive if there are three jointly pivotal suppliers on that path. All non-candidate transmission paths are declared non-competitive, without subjecting them to this prospective test for the existence of three jointly pivotal suppliers.

Given this designation of competitive and non-competitive transmission paths, the existing LMPM mechanism follows a three-step process for determining generation unit-level schedules and locational marginal prices (LMPs). First, the market pricing model is run imposing only the competitive transmission constraints and relaxing all non-competitive constraints (setting their capacity to be infinite). This yields CC generation unit-level schedules and LMPs. Then the market pricing model is run imposing all transmission constraints, which produces the AC generation unit-level schedules and LMPs. If any generation unit's AC schedule exceeds its CC schedule, then the offer curve of this generation unit is subject to bid mitigation through the process described above. The third step re-runs the pricing model with all constraints and all mitigated offers to compute generation unit-level schedules and prices. This three-step process for local market power mitigation is repeated in both the day-ahead and real-time markets.

As noted above, we believe that a strength of the current LMPM mechanism is the fact that over-mitigation is highly unlikely to occur because the mitigated bid price is very likely to be greater than or equal to the bid price a unit would submit if it had no ability or incentive to exercise unilateral market power. A potential weakness of the current approach is related to methodology used to construct a supplier's DEB. If a supplier is mitigated to frequently, this can destroy the incentive for that supplier to produce in a least cost manner. Specifically, if the supplier knows that its cost-based DEB will be used in the pricing process, it may take actions to increase the verified variable cost and magnitude of the bid adder. In this way, the supplier can exercise unilateral market power by raising these verifiable costs. Therefore, an LMPM mechanism that mitigates a supplier only when it truly does not face adequate competition, will provide the strongest possible incentives for the supplier to focus on least-cost production, rather than on increasing its cost-based DEB.

For this reason, we are currently investigating alternatives to the current LMPM mechanism that rely on the most up-to-date information on the ability of a generation unit owner to exercise unilateral market power, so as to mitigate the supplier only when the generation unit owners has a significant ability to exercise local market power. At the March 19, 2010 MSC meeting a number of generation unit owners expressed support for a LMPM mechanism that relies on actual system conditions to determine whether a supplier has the ability to exercise local market power. Such an approach would necessarily have to rely on more indexes of the ability and incentive to exercise unilateral market power that can be computed very quickly, rather than on the extensive analysis of the competitiveness of transmission paths in the current LMPM mechanism.

The major challenge to designing an approach that is more reflective of actual system conditions is finding metrics that can be quickly computed, yet still catch the vast majority of instances when a supplier has the ability to exercise significant unilateral market power, while also limiting the frequency of mitigation when the supplier has little ability to exercise unilateral market power. We are currently engaged in analysis to determine whether such an approach can be devised and are planning to monitor how it would perform relative to the California ISO's current LMPM mechanism. The following section summarizes our current thinking on this research.

6. Alternative Approaches to LMPM Mitigation in California

This section describes the residual demand curve-based approach to measuring the ability of a generation unit owner to exercise unilateral market power.[5] Measures constructed from the residual demand curve utilize the bids and offers of market participants submitted to the day-ahead and real-time markets and therefore provide measures of the ability and incentive of a supplier to exercise unilateral market power based on actual market conditions.

6.1. The Residual Demand Curve

Each day, generation unit owners submit to the California ISO their willingness to supply energy from their generation units as a function of the market price for each hour of the following day. For all wholesale electricity markets in the United States, these willingness-to-supply functions are step functions, with the height of each step equal to the offer price at which the owner of the generation unit is willing to supply an amount of output equal to the length of the step. For example, in the California ISO, each supplier is allowed to submit up to 10 price levels and associated quantity increments for each generation unit each hour of the day. The ability to submit different price offers for different levels of output from the generation unit accounts for the fact that the variable cost of producing electricity can vary with the level of output in the current period and in previous time periods.[6] Because each generation facility is typically composed of multiple generation units, and firms usually own many generation facilities, these firm-level willingness-to-supply curves can be composed of hundreds of price levels and quantity increments each hour of the day. To simplify the subsequent graphical

[5] We have previously recommended consideration of this approach to identifying unilateral market power for possible mitigation, for example during the May 24, 2005 MSC meeting, http://www.caiso.com/docs/09003a6080/36/1a/09003a6080361a3d.pdf .

[6] Wolak (2007) presents evidence from generation unit-level bidding and operating behavior in the Australian electricity market that unit-level marginal costs vary with the level of output in the current and neighboring time periods of the day.

analysis, we assume these willingness-to-supply functions and all marginal cost functions are smooth.

In the absence of congestion and losses in the transmission network, the market operator takes the willingness-to-supply curve from each generation unit owner and computes an aggregate supply curve for each hour of the following day. In single zone-pricing a market, a market-clearing price is determined by the price at which the aggregative willingness-to-supply curve intersects the aggregate demand for that hour. Figure 1 plots the firm-level willingness-to-supply curves for a wholesale electricity market with three suppliers. The vertical axis denotes the market price and the horizontal axis the quantity that each firm is willing to supply at that price.

Let $S_1(p)$, $S_2(p)$, and $S_3(p)$ equal the willingness-to-supply curves of Firms 1, 2, and 3, respectively. At a price of $60/MWh, Firm 1 is willing to supply 200 MWh, Firm 2 is willing to supply 100 MWh, and Firm 3 is willing to supply 300 MWh. The aggregate willingness to supply curve, $S_T(p)$, is the sum of the amounts that the three firms are willing to supply at each possible price. The vertical line denotes the market demand, Q_d, which is equal to 600 MWh. The price at the intersection of the market demand with the aggregate willingness-to-supply curve is the market-clearing price, which is $60/MWh.

To construct a measure of the hourly firm-level ability of a supplier to exercise \unilateral market power with single zone-pricing, we use the market demand and the willingness-to-supply functions of all other firms besides the one under consideration to construct the residual demand faced by the firm under consideration. Let Firm 1 be the supplier whose ability to exercise unilateral market power we would like to measure and assume for the moment that Firm 1 can observe the market demand and the willingness-to-supply curves of

Firms 2 and 3. This is clearly not the case in reality because all firms must submit their willingness-to-supply curves at the same time and the value of the market demand is typically unknown when they do. However, this assumption simplifies the presentation and will be relaxed once a number of important concepts have been introduced.

At each price, Firm 1's residual demand is the amount of market demand left for Firm 1 given the willingness-to-supply curves of all its competitors. As we demonstrate below, this general definition of Firm 1's residual demand curve can be extended to the case of a zonal-pricing market and even a nodal-pricing market. In all of these cases, the residual demand that a generation unit owner faces is the amount of the market demand left unsupplied at a given market price after the willingness supply of all other market participants and all relevant transmission network constraints have been taken into account. In the case of a single zone pricing, the graphical description described below can be used to construct the residual demand curve. For the zonal-pricing and nodal-pricing markets, the market pricing software must be used to compute the value of a generation unit owner's the residual demand curve at each price level.

Figure 2 computes the Firm 1's residual demand for the case of a single zone pricing market. It is computed by taking the difference between the market demand and the amounts that Firms 2 and 3 are willing to supply at that price. At a price of $60/MWh, Firm 2 is willing to supply 100 and Firm 3 is willing to supply 300, so the residual demand facing Firm 1 is 200, the difference between the market demand of 600 and the sum of the willingness-to-supply quantities of Firms 2 and 3. The curve D_1 is the residual demand curve for Firm 1 that results from applying this procedure for all prices between $0/MWh and $90/MWh.

The theory of profit-maximizing behavior by a monopoly yields the price that maximizes Firm 1's profits given this residual demand curve, which depends on the market demand and willingness-to-supply curves of Firm 1's competitors. Figure 3 reproduces Firm 1's residual demand curve from Figure 2, D_1, and adds the marginal revenue curve, MR_1, associated with this residual demand curve, along with Firm 1's marginal cost curve, MC_1. A profit-maximizing monopolist produces at the level of output where marginal revenue equals marginal cost, $MR_1 = MC_1$, which implies that Firm 1 produces 200 MWh. If Firm 1 produces 200 MWh, its residual demand curve yields a market-clearing price of $60/MWh. Firm 1's gross margin (i.e., profit, disregarding fixed costs) for this residual demand curve and marginal cost function combination equals the shaded area above its marginal cost curve and below the market-clearing price of $60/MWh. Firm 1 cannot obtain higher profits at any other price or level of output -- given the willingness-to-supply curves of its competitors and the market demand -- than it does at this price and quantity pair. For this reason, the price and quantity pair ($60/MWh, 200 MWh) is called the "best-reply" price and quantity pair for Firm 1 for the residual demand curve realization D_1.

As noted above, the construction of Firm 1's expected profit-maximizing willingness-to-supply function is complicated by the fact that it does not know the actual residual demand curve realization that it will face when it submits this curve to the market operator. However, firms are typically able to observe the level of market demand and the willingness-to-supply curves of their competitors after the market closes for the day. Although the aggregate demand for electricity varies considerably across hours of the day, week, or year, it can be forecast accurately on a day-ahead basis. The physical operating characteristics and availability of all generation units in the wholesale market are usually known to all market participants at the time that they submit their willingness-to-supply curves. These facts, even without the availability of previous market demand and willingness-to-supply curves, provide valuable information about the set of possible residual demand curves that each firm might face and the probability that it will face each of these residual demand curves.

The key conclusion to draw from this analysis is that the distribution of residual demand curves that a supplier faces during a given hour of the day is the key determinant of how much higher the hourly offer price of this profit-maximizing supplier will be above the marginal cost of production at each level of output. Steeper residual demand curves imply expected profit-maximizing offer prices higher above the generation unit owner's marginal cost. Flatter residual demand curve distributions imply expected profit-maximizing offer curves closer to the generation unit owner's marginal cost. Therefore, the distribution of the residual demand curves that a supplier faces, regardless of the congestion management mechanism used by the market operator—single zone, zonal-pricing, or nodal-pricing—determines the ability of a supplier to exercise unilateral market power.

A firm's residual demand curve can be used to construct a summary measure of its *ability* to impact the market price by its unilateral actions. Figure 4 graphs two possible residual demand curves for Firm 1, D_1, and one that is much steeper, $D_1^{\#}$. Both curves pass through the price and quantity pair ($60/MWh, 200 MWh). If Firm 1 faced D_1, by selling 50 MWh less, reducing its output from 200 MWh to 150 MWh, the market-clearing price would increase to $67/MWh. If Firm 1 instead faced $D_1^{\#}$, by selling 50 MWh less it would raise the market-clearing price substantially, from $60/MWh to $90/MWh. Consequently, a supplier that faces a steeper residual demand curve has a much greater ability to raise the market price by withholding output than does a supplier that faces a flatter residual demand curve.

The steepness of a residual demand curve can be measured in way that does not depend on the units used to measure prices and quantities. The price elasticity of demand is defined as the percentage change in the residual demand at price P that results from a one percent increase in this price:

$$\varepsilon(\mathrm{P}) = \frac{\text{Percentage Change in Residual Demand}}{\text{Percentage Change in Price}}.$$

The inverse of this demand elasticity measures the percentage change in the market-clearing price that results from a one percent reduction in the firm's output at price P. The absolute value of this inverse elasticity can be thought of as a measure of the *ability* of the firm to raise the market-clearing price by reducing its willingness to supply electricity.[7] The inverse elasticity provide a local, near the price P, measure of the ability of firm to exercise unilateral market power.

Other features of the residual demand curve, DR(p), that Firm 1 faces can be used to compute other indices of the ability of a supplier to exercise unilateral marker power. For example, computing the value of the residual demand curve at the maximum possible price in the market, p_{max}, provides another measure of the ability of the supplier to exercise unilateral market power. Specifically, if the value of the residual demand curve at p_{max} is greater than zero, $DR(p_{max}) > 0$, then Firm 1 is said to be pivotal in the sense that Firm 1 must supply at least $DR(p_{max}) > 0$, or there will be insufficient supply to meet the market demand given the offers of all other firms besides Firm 1 and the characteristics of the transmission network used in the pricing model.

[7] Wolak (2003b) computes hourly residual demand elasticities for the five largest suppliers in the California wholesale electricity market to understand changes in their bidding behavior between the summers of 1998 and 1999 and the summer of 2000 when wholesale electricity prices in California rose dramatically.

It is also possible to compute a residual demand curve for single generation unit, single supplier, or any group of suppliers and in an analogous manner. To compute the residual demand curve for a single generation unit, simply subtract the willingness-to-supply curves of all other generation units owned by that supplier from its residual demand curve. To compute the residual demand curve facing a group of suppliers take the market demand and only subtract the willingness supply curves of firms not included in this groups of suppliers. For example, to compute the residual demand curve facing the three largest suppliers, take the market demand curve and subtract the willingness to supply curves of all other suppliers besides these three suppliers. Call this residual demand curve $DR_3(p)$. If $DR_3(p_{max}) > 0$, then these three suppliers are said to be jointly pivotal, because some output if required from these three suppliers or the market cannot be met given the offers the remaining suppliers.

6.2. Ability versus Incentive to Exercise Unilateral Market Power

All of the characteristics of wholesale electricity markets described above tend to make the elasticity of the residual demand curves faced by large suppliers extremely small in absolute value, which implies extremely large inverse elasticities and very large market-clearing price increases from a supplier's withholding a small percentage of its output. This greater ability to exercise unilateral market power may not translate into an increased exercise of unilateral market power, if the supplier has no incentive to exploit this ability to exercise unilateral market power. The amount of fixed-price forward market obligations—both fixed-price retail load obligations and fixed-price forward contracts determines the incentive a supplier has to exercise unilateral market power.

Electricity retailers sign fixed-price forward contracts that guarantee the price at which they can purchase a fixed quantity of electricity or vertically-integrated generation unit owners have fixed-price retail load obligations. Let P_c equal the price at which the supplier agrees to sell energy to an electricity retailer and Q_c equal the quantity of energy sold at that price. This contract is negotiated in advance of the date that the generation unit owner will supply the energy, so that the values of P_c and Q_c are pre-determined from the perspective of the supplier's behavior in the short-term wholesale market.[8]

For the same residual demand curve realization, the larger a supplier's fixed-price forward contract obligations are, the lower will be the offer price that it finds profit-maximizing, because the firm only earns the short-term market price on the difference between its actual production and its forward contract quantity. Therefore, the revenue increase from raising the short-term price is smaller when the firm's forward contract quantity is larger relative to its actual production. Figure 5 reproduces the residual demand curve and marginal cost curves for Firm 1 from Figure 3. Suppose that Firm 1 has a fixed-price forward contract obligation of 100 MWh. Firm 1's level of actual output still determines the market-clearing price set by its residual demand curve. For example, if Firm 1 produces 200 MWh, the market-clearing price would be \$60/MWh as in Figure 3. However, this forward contract obligation alters Firm 1's revenues because it only receives the \$60/MWh market-clearing price for 100 MWh. The remaining 100 MWh (of the 200 MWh produced) is sold at P_c, the price in the fixed-price forward contract obligation.

To determine the change in total revenues to Firm 1 from withholding one MWh of output with 100 MWh of fixed-price forward contract obligations, Figure 5 plots Firm 1's residual demand curve less its fixed-price forward contract obligations, which are effectively sold at P_c instead of the market-clearing price. The marginal revenue curve for D_1 - Q_c, the net-

[8] Of course, greater price inelasticity in the spot market means that demand will also be more inelastic in the forward market, and this can result in exercise of market power unless the contracts are signed far enough in advance to allow new entrants to compete to sell these contracts.

of-forward-contracts residual demand curve facing Firm 1, is constructed following the standard approach to constructing marginal revenue curves. To convert $MR_{D_1 - Q_c}$, the marginal revenue curve associated with the net-of-forward-contracts residual demand curve, to the marginal curve associated with Firm 1's output, shift $MR_{D_1 - Q_c}$ to the right by the amount of Firm 1's fixed-price forward contract forward obligations. This curve is plotted as MR_Q, and comparing it to MR_1 in Figure 3 reveals that it is uniformly higher at every level of output, which implies a point of intersection of MR_Q with MC_1 at a higher level of output than the 200 MWh shown in Figure 3.

The profit-maximizing level of output for Firm 1 for the residual demand curve D_1 and fixed-price forward contract obligation $Q_c = 100$ shown in Figure 5 is 224 MWh, which implies a lower market-clearing price of \$56/MWh. This figure demonstrates the general result that for the same residual demand curve realization, the larger a supplier's fixed-price forward contract obligation is, the larger will be its best-reply output level and the smaller will be its best-reply price. Extending this logic to the computation of expected profit-maximizing willingness-to-supply curves, implies that for the same distribution of residual demand curves, a larger quantity of fixed-price forward contract obligations leads to a greater willingness to supply output by Firm 1 at each possible market price.[9]

The elasticity of a supplier's residual demand curve net of its fixed-price forward contract obligations measures its *incentive* to raise prices in the short-term market. Let $\varepsilon^C(P)$ denote this magnitude, which is defined as the percentage change in the difference between the firm's residual demand at price P and its forward contract position brought about by a one

[9]Wolak (2000) uses bid, market outcome and forward contract quantity data for large supplier in the Australian wholesale electricity market to demonstrate the sensitivity of a supplier's incentive to influence the short-term market price to the value of its fixed price forward contract obligations.

percent increase in price. If the firm has positive amount of fixed-price forward contract obligations, then a given change in the firm's residual demand as a result of a one percent increase in the market price, implies a much larger percentage change in the firm's net-of-forward-contract-obligations residual demand. For example, suppose that a firm is currently selling 100 MWh, but has 95 MWh of forward contract obligations. If a one percent increase in the market price reduces the amount that the firm sells by 0.5 MWh, then the elasticity of the firm's residual demand is -0.5 = (0.5 percent quantity reduction) ÷ (1 percent price increase). The elasticity of the firm's residual demand net of its forward contract obligations is -10 = (10 percent net of forward contract quantity output reduction) ÷ (1 percent price increase). Thus, the presence of fixed-price forward contract obligations implies a dramatically diminished *incentive* to withhold output to raise short-term wholesale prices, despite the fact that the firm has a significant *ability* to raise short-term wholesale prices through its unilateral actions.

In general, $\varepsilon^C(P)$ and $\varepsilon(P)$ are related by the equation:

$$\varepsilon^C(P) = \varepsilon(P)(\text{Actual Output}/[\text{Actual Output} - Q_c]).$$

The elasticity of the firm's residual demand curve net of its fixed price forward contract obligations is equal to the elasticity of its residual demand curve times the ratio of its total output to its output net of forward market commitments. This equation implies that any non-zero value of $\varepsilon(P)$, which quantifies a firm's *ability* to raise market-clearing prices by its unilateral actions, can be translated into a very small *incentive* to raise market-clearing prices (a large value of $\varepsilon^C(P)$ in absolute value) through a large enough value of forward contract obligations relative to actual output.

If all suppliers have significant fixed-price forward market obligations, then expected profit-maximizing bidding behavior by Firms 2 and 3 implies that these firms will submit willingness-to-supply curves with higher levels of output at each possible price than those given in Figure 2. The logic used to construct the residual demand curve facing Firm 1 described in Figure 3 implies that it will now face a much flatter residual demand curve. Figure 5 implies that Firm 1 will now have reduced ability to withhold output to raise the market-clearing price because a 1 MWh reduction in output will increase the market-clearing price by less. This logic demonstrates that a high level of fixed-price forward market obligations for all suppliers in a wholesale market reduces both the unilateral *incentive* and *ability* of a supplier to exercise unilateral market power.

6.3. Zonal-Pricing Transmission Constrained Residual Demand Curves

Transmission network constraints can significantly reduce the number of generation units and independent suppliers that are able to serve a location or set of locations in the transmission network. Returning to the three-firm example, suppose that (a) Firm 3 is distant from either Firm 1 or Firm 2 and (b) there is a transmission line with finite capacity between Firm 3's location and the location of Firms 1 and 2. Figure 6 illustrates the impact of this transmission constraint on construction of the residual demand curve facing Firm 1, using the same supply curves as in Figure 2. The only difference is that a maximum of 300 MWh of Firm 3's supply can actually compete against Firm 1 and Firm 2 because that is the capacity of the transmission interface between Firm 3's location and the location of Firms 1 and 2. This transmission constraint implies that Firm 3's effective supply curve for the purposes of computing Firm 1's residual demand curve becomes vertical at a supply of 300 MWh. Figure 6 plots the residual demand curve faced by Firm 1 with this transmission constraint taken into account. For all output levels, this curve is at least as steep or steeper than the residual demand calculated in Figure 3, which does not account for transmission constraints.

This example demonstrates how transmission constraints can reduce the opportunities for consumers to shift to alternative sources of supply and shrink the geographic size of the market. In Figure 6, at prices above \$60/MWh, the value where the supply from Firm 3 is equal to 300 MWh, Firms 1 and 2 no longer face competition from Firm 3. In this sense, the transmission network has limited the size of the market in which Firms 1 and 2 compete.

6.4. Nodal-Pricing Transmission Constrained Residual Demand Curves

In a nodal-pricing market it is possible to compute the residual demand curve that a generation unit owner faces. To identify the price and quantity pair on the nodal-pricing residual demand curve for a generation unit, compute nodal prices using the actual locational demand curves and the willingness-to-supply curves of all generation units except the one under consideration. For this generation unit, say Generation Unit A, submit a vertical willingness-to-supply curve at a pre-specified quantity level, say q^*, and solve for the nodal prices. The nodal price at the location of Generation Unit A is the associated price on the residual demand curve facing this generation unit at output level q^*. Repeating this procedure for every output level from zero to the capacity of the generation unit yields the nodal-pricing residual demand curve facing that generation unit. It is also possible to compute a nodal-pricing residual demand curve for a portfolio of generation units at different locations following an analogous approach.

The major challenge with computing a residual demand curve in a nodal-pricing market is the computational time necessary to compute each point on the residual demand curve at each generation unit's location in the transmission network. This can be an extremely tedious and time-consuming process, and may not be necessary if the frequency and magnitude of transmission congestion is low. However, particularly when system conditions are stressed as certain locations in the transmission network, ignoring the transmission network configuration may severely under-estimate the ability to exercise local market power that a generation unit possesses.

6.5. Use of Residual Demand Curve in Local Market Power Mitigation

Potential utilization of a residual demand curve calculation would be two-fold; as a analytical tool for evaluating traditional LMPM procedures and, eventually, as an alternative form of LMPM itself. First, these calculations can be utilized to provide an ex-post measure of the "true" level of potential market power on an hourly and locational basis. These measures can then be compared to the more blunt estimates of local market power implied by the current CAISO CPA method. This would provide the best estimate of how well the current LMPM procedures capture the true level of local market power and would allow analysts to quantify the extent of "false positives" as well as "false negatives" from the current mitigation procedure.

Because the inverse elasticity of the residual demand curve precisely quantifies the ability of a generation unit owner to move market prices through its unilateral actions, one would expect that when the value of this index of the ability to exercise unilateral market power is larger, suppliers submit offer prices that are higher relative to their marginal cost. McRae and Wolak (2009) provide empirical evidence that this is in fact the case for the four largest suppliers in the New Zealand wholesale electricity market. McRae and Wolak (2009) also find that when the index of the incentive of a supplier to exercise unilateral market power is greater, each of the four larger suppliers also submit substantially higher offer prices relative to their marginal cost.

This evidence suggests that it may be promising to base a local market power mitigation mechanism on the actual value of the inverse elasticity of the residual demand curve and the inverse elasticity of the net-of-forward-market-obligations residual demand curve. Both of these indices can be computed for each hour of the day given the bids and offers submitted to the California ISO market. If the values of these two indices are sufficiently high, indicating a large ability and incentive of a generation unit owner to exercise local market power, this generation unit could have its offers subject to mitigation.

A major challenge with implementing such a mechanism under the new nodal market design is that computing the nodal-pricing residual demand curve faced by a supplier can be extremely time-consuming. Furthermore, fixed-price forward market obligations need to be known with some accuracy to compute the indices of the incentive of a supplier to exercise unilateral market power. However, it is straightforward to compute a single zone residual demand curve that a single generation unit or portfolio of generation units faces. This involves following the graphic procedure described above, and many residual demand curves can be computed quickly. Inverse elasticities for these residual demand curves can also be computed easily. Consequently, one approach to local market power mitigation would be to compute the single zone-pricing inverse elasticities and, depending on the values obtained for these indexes of the ability and incentives to exercise unilateral market, the ISO could then undertake a more detailed computation for the subset of the generation units with very large single zone-pricing inverse elasticities.

The major advantage of a residual demand curve based approach to local market power mitigation is that it could be much more dynamic than current procedures. It could in theory be applied each hour of the day, so that mitigation would only occur for units with high inverse elasticities during that hour. However, there are many challenges to adopting this approach to local market power mitigation. This approach would produce hourly indexes of the ability and incentive of individual suppliers or generation units to exercise unilateral market power could address the desire of some stakeholders to have a LMPM mechanism that is more responsive to real-time system conditions.[10]

7. Concluding Comments

After about one full year of operation under the MRTU design, we believe that the current LMPM mechanism is operating satisfactorily and that changes to this procedure are not warranted at this time. The overall competitiveness of the California market under MRTU has been very high. However, because the past year under the new market design was characterized by relatively low load levels and little transmission congestion, we believe that it would be imprudent to make any immediate changes to the current LMPM mechanism.

In the near-term a reasonable mitigated price level combined with improved scarcity pricing implies that concerns over the frequency of mitigation are largely offset by reasonable levels of mitigation. Over the long-term too much reliance upon cost-based DEBs can weaken incentives for reducing costs, so it is still important for the CAISO to continue to improve the precision of the timing of its mitigation.

Although we believe there is significant promise in basing a LMPM mechanism on a supplier's residual demand curve, a considerable amount of analysis of the relative performance of the California ISO's current approach to LMPM and possible other approaches based on the indexes of the ability and incentive of suppliers to exercise unilateral market power based on the residual demand curve is necessary before we would recommend any significant changes in the current LMPM mechanism. Moreover, this comparative analysis should be based on higher

[10] For practical procedures for calculating residual demand curves for nodal markets considering network constraints, see Xu and Baldick (2007).. Conceptually related approaches for estimating the elasticity of the residual demand in the neighborhood of a market solution are proposed by Lesieutre et al. (2006) and Oh and Thomas (2010).

load levels and more extreme weather conditions system conditions than existing during the first year of operation of the new market.

Nevertheless, we will continue to monitor the performance of the existing LMPM mechanism and explore potential alternative approaches that are more reflective of actual system conditions and therefore more likely to enhance overall market efficiency.

References

Lesieutre, Bernie C., Oh, HyungSeon, Thomas Robert J. and Donde, V. "Identification of Market Power in Large-Scale Electric Energy Markets," Proceedings of the 39th Annual Hawaii International Conference on System Sciences, 2006, p. 240.2.

McRae, Shaun D. and Wolak, Frank A. "How Do Firms Exercise Unilateral Market Power? Evidence from a Bid-Based Wholesale Electricity Market," 2009, available at http://www.stanford.edu/~wolak.

Oh, HyungSeon and Thomas, Robert J., Estimation of a Sensitivity-Based Metric for Detecting Market Power, Journal of Energy Engineering, 2010.

Wolak, Frank A., "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market," *International Economic Journal*, 2000, 14(2), 1-40.

Wolak, Frank A., "Identification and Estimation of Cost Functions Using Observed Bid Data: An Application to Electricity," *Advances in Econometrics: Theory and Applications, Eighth World Congress, Volume II*, Mathias Detwatripont, Lars Peter Hansen, and Stephen J. Turnovsky (editors), Cambridge University Press, 2003a, 133-169.

Wolak, Frank A., "Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market 1998 to 2000," *American Economic Review*, 93 (May 2003b): 425-430.

Wolak, Frank A. "Quantifying the Supply-Side Benefits from Forward Contracting in Wholesale Electricity Markets," forthcoming 2007, *Journal of Applied Econometrics.*

Xu, Lin and Ross Baldick, Ross."Transmission-constrained Residual Demand Derivative in Electricity Markets," IEEE Transactions on Power Systems, 22(4):1563-1573, November 2007 (available: http://users.ece.utexas.edu/~baldick/papers/residual.pdf)

Figure 1: Aggregate Willingness-to-Supply Curve and Market-Clearing Price

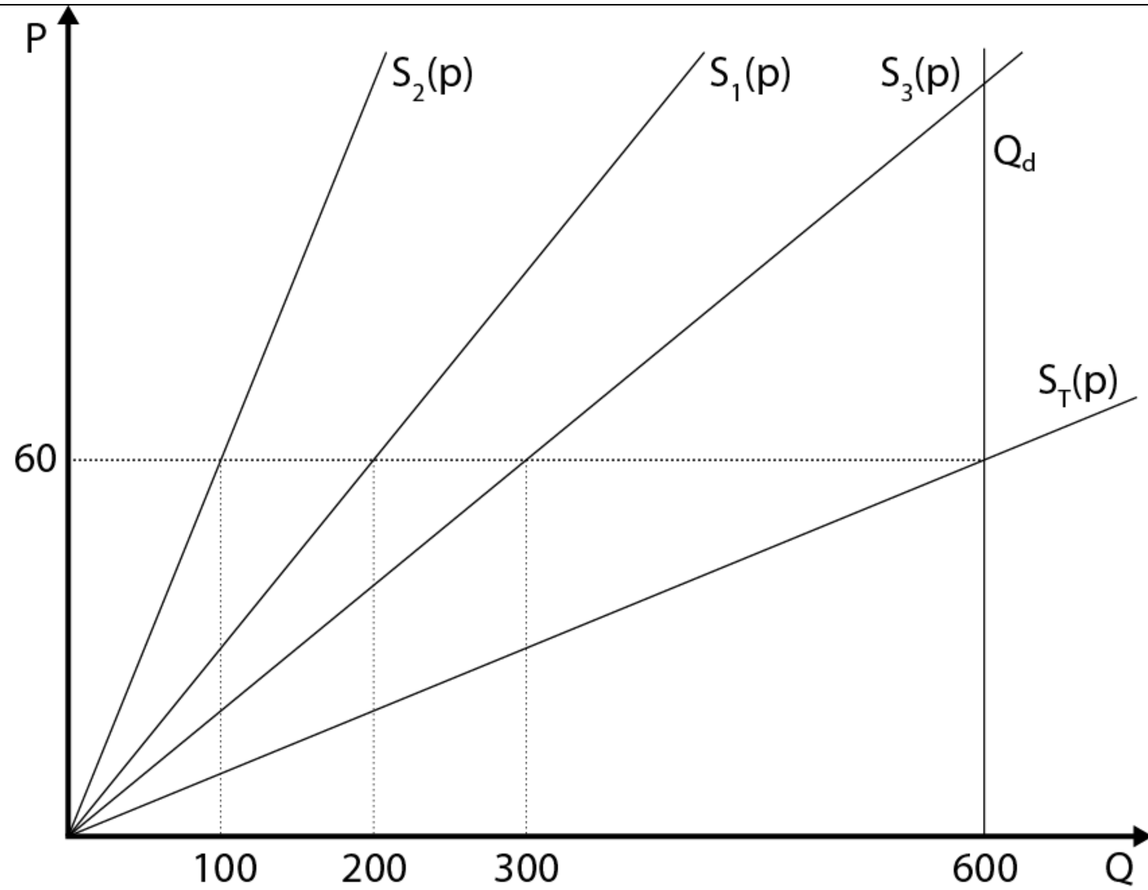

Figure 2: Construction of Residual Demand Curve of Firm 1

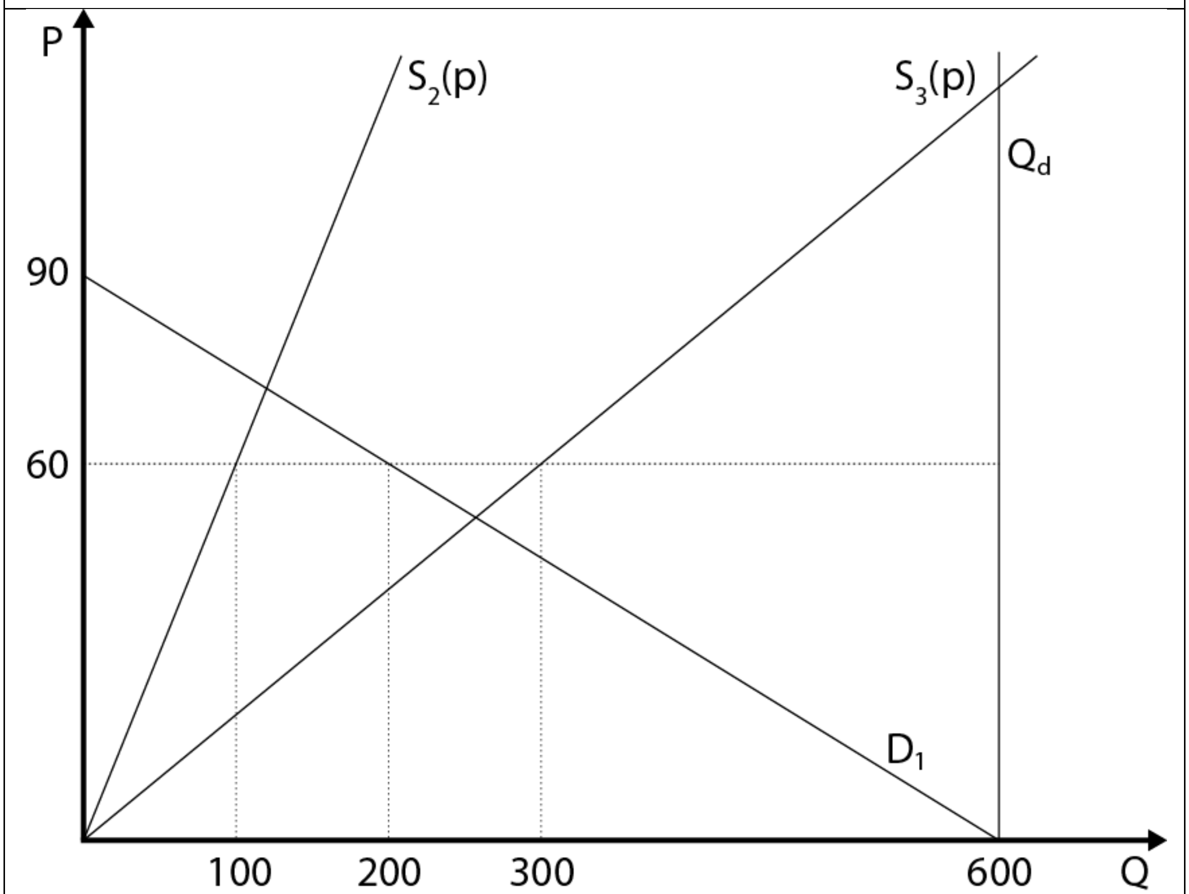

Figure 3: Calculation of Best-Reply Price and Quantity for Firm 1

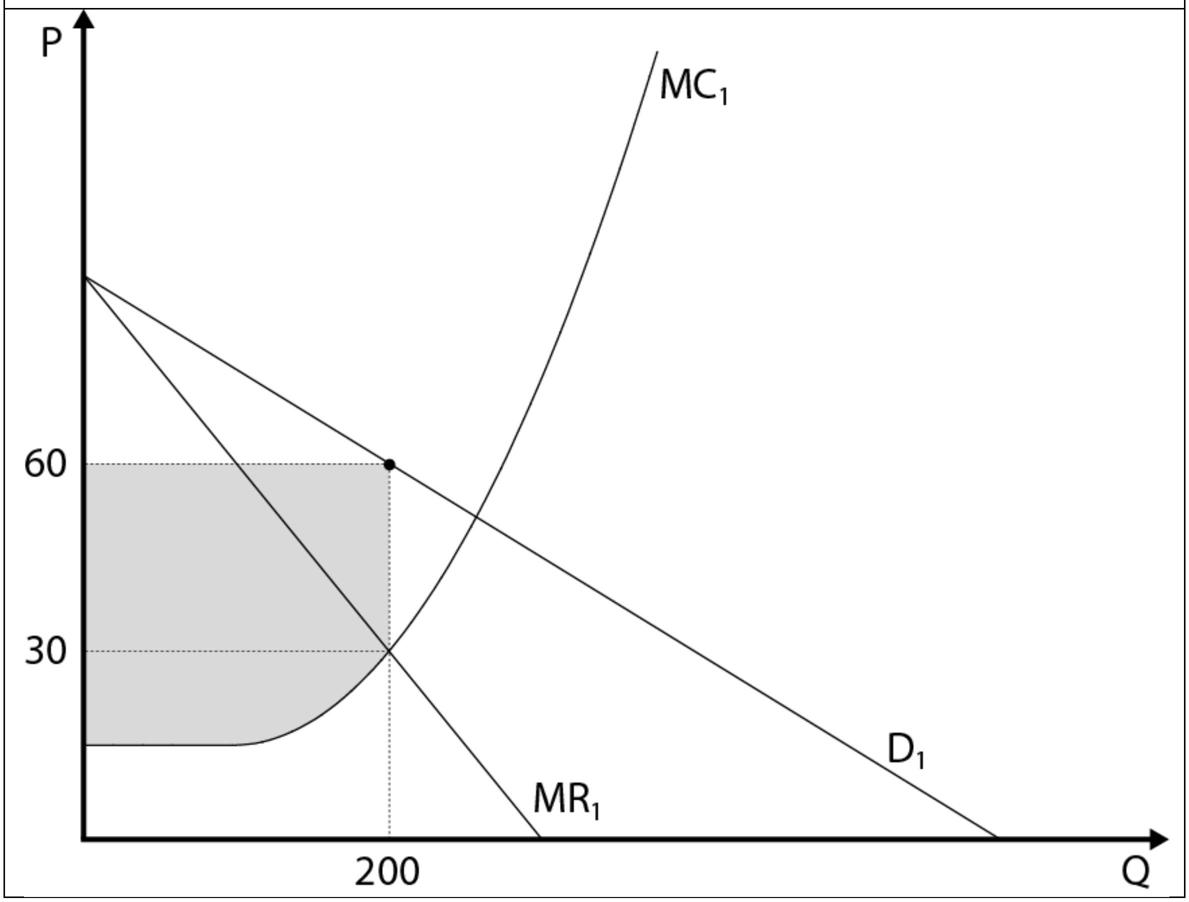

Figure 4: Form of Residual Demand Curve and Price Increase from Withholding Output

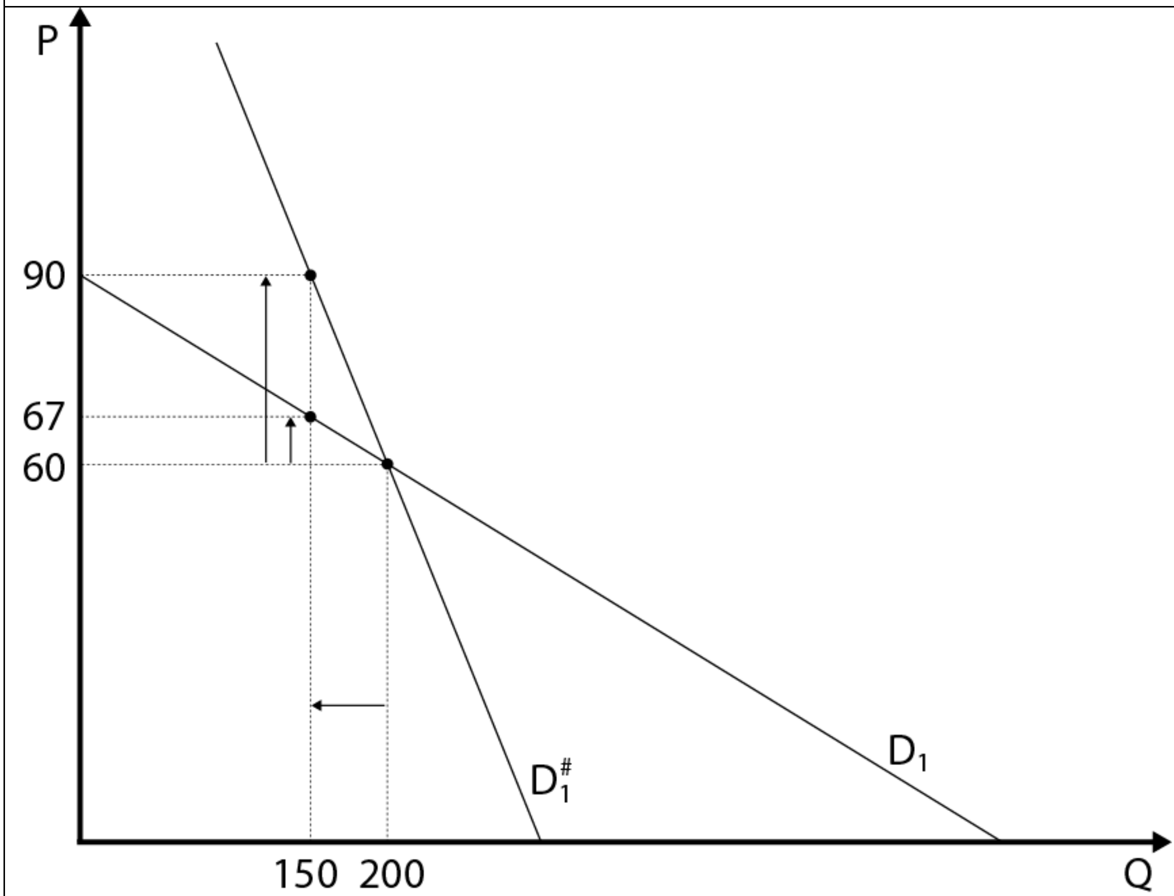

Figure 5: Best-Reply Price and Quantity with Contracts

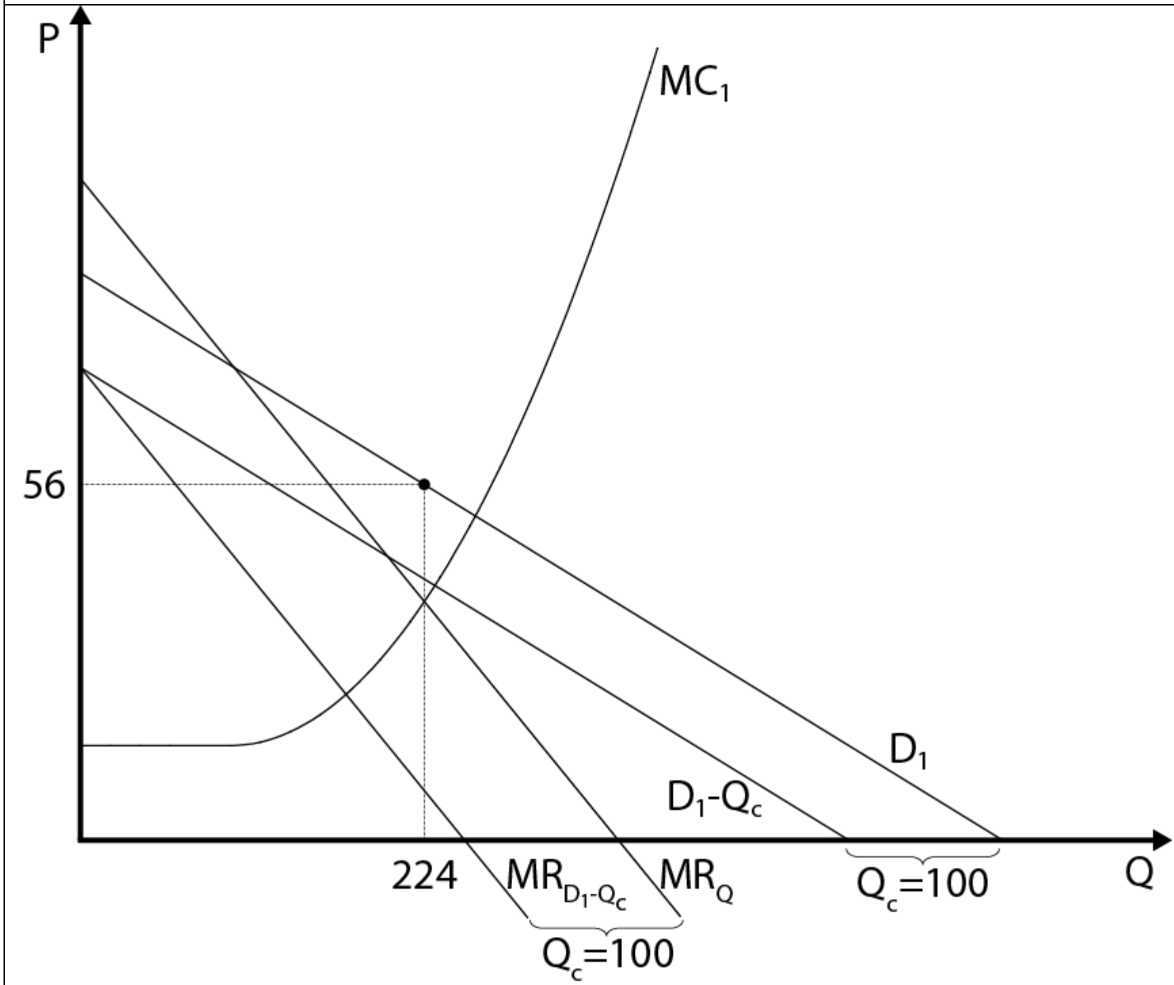

Figure 6: Residual Demand of Firm 1 with Transmission Constraints