Nodal and Zonal Congestion Management and the Exercise of Market Power

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I. Introduction

Transmission constraints in electric networks can limit competition and create pockets of local market power. The policy response to this reality includes many elements ranging from special contracting arrangements to divestiture of assets. Although a full analysis of the impacts of local market power is complex and context specific, there are some general principles that can guide the discussion.

One principle often applied is that the existence of local market power must necessarily be exacerbated in a market model that applies nodal pricing principles. The argument is that if the prices are different at every node, so must be the markets and, therefore, use of nodal pricing must enhance the ability of the monopolist to increase its profits. A common conclusion follows that administrative aggregation of many nodes into larger zones would ensure competition across a wider area and constrain this power of the monopolist. Hence, nodal pricing or splitting of zones should be pursued only when there is workable competition at each node or in each new zone.

This argument is incorrect. In fact, as stated it is exactly backwards. Other things being equal, zonal pricing always subsidizes the dominant local generator and increases monopoly profits above those that would occur under nodal pricing.

This paper examines this assertion through a number of illustrative examples and a supporting theoretical analysis. These argue for the use of nodal pricing as generally

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preferred in the presence of local market power. To be sure, nodal pricing will not eliminate the market power and additional approaches to market power mitigation would be indicated. The scope and effectiveness of these additional measures would be enhanced through application in combination with nodal pricing.

For some readers the arguments may seem obvious, in which case the benefit of this analysis is only to expand on the obvious.[2] However, the persistence of the argument that market power dictates a need for zonal aggregation motivates the detailed demonstration that this is both wrong and creates a set of new problems that could be avoided with nodal pricing or splitting congested zones.

II. Zones, Nodes and Workable Competition

The argument that market power is enhanced under nodal pricing is found in many places. For example, the design of the California market appears to have been motivated in part by a concern over the exercise of local market power. Recall that in California the market is divided into a number of zones that aggregate locations where there is expected to be little or no transmission congestion or constraints.

> Zones are defined as areas where congestion is infrequent and can be easily priced on an average cost basis. By definition, congestion within zones is infrequent and possibly difficult to predict. Therefore, financial rights will be difficult to auction and to resell in a secondary market. Congestion between zones is defined to be frequent with large impacts. Therefore, marginal cost pricing promotes its efficient use. Marginal Cost of transmission is the value that market participants place on congested transmission. Marginal Cost is based on scheduling and bidding information for hourly consumption in the relevant forward or spot market. Marginal cost pricing provides the economic incentives that promote the allocation of the limited transmission capacity to the most cost-effective users.[3]

The interest in efficient markets and the view that markets provide superior tools for responding to marginal cost pricing signals gives rise to the California policy of splitting zones whenever there is any significant degree of congestion.

> The marginal cost of using a congested interzonal interface is defined as the incremental value of that interface to the marginal user. This marginal

[2] This is another example of the perverse incentive effects of price averaging; see Federal Energy Regulatory Commission, "Regional Transmission Organizations," Final Rule, Washington DC, December 20, 1999, p. 642.

[3] Ziad Alaywan, "Facilitating the Congestion Management Market in California," California Independent System Operator, April 1999, p. 4.

> cost is paid by all [Scheduling Coordinators] that want to use a congested interzonal interface. Intrazonal congestion pricing sets the congestion pricing per unit of energy to the average cost of relieving congestion within the zone. California ISO's Congestion Management process can define new zones if intrazonal congestion becomes frequent and inefficiently priced at average cost. Likewise, zones will be combined if interzonal congestion becomes infrequent and inefficiently priced at marginal cost.[4]
>
> Intrazonal congestion is expected to be infrequent and have small impact. If intrazonal congestion occurs frequently with large impact, a new zone will be created. The ability to create new zones when intrazonal congestion reaches a limit means that any pricing inefficiency caused by as-bid pricing and not paying for counterflow schedules will be small and self-correcting (through new zone creation and marginal cost between the new zones).[5]

The current threshold for congestion induced zone splitting in California is called the 5% criterion, the details of which are not important here. However, this policy of using markets and sending marginal cost pricing signals to deal with transmission constraints is itself constrained by a concern over the effect of local market power. In particular, the separation of a constrained zone into its components is limited by a requirement that the resulting zones be workably competitive.

> Besides the 5% criterion that was used to form congestion Zones, another criterion was further used to determine if a Zone would be *Active* or *Inactive*. If workable competition is present on both sides of the Inter-Zonal Interface the Zone is active, otherwise inactive.[6]
>
> The absence of effective competition within the Inactive Zones gives market power to the few owners of generating units within these Zones that could theoretically drive the corresponding zonal price arbitrarily high should there be Congestion Management on the inactive interface.[7]

The limitation is clear, and the appeal to the perverse effects of local market power is

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4 Ziad Alaywan, "Facilitating the Congestion Management Market in California," California Independent System Operator, April 1999, p. 4.

5 Ziad Alaywan, "Facilitating the Congestion Management Market in California," California Independent System Operator, April 1999, p. 7.

6 California Independent System Operator, "Report to the Federal Energy Regulatory Commission: Studies Conducted Pursuant to the October 30, 1997 Order," December 1, 1999, p. 14.

7 California Independent System Operator, "Report to the Federal Energy Regulatory Commission: Studies Conducted Pursuant to the October 30, 1997 Order," December 1, 1999, p. 17.

taken for granted. The underlying arguments are seldom exposed. It would seem natural that the motivation is to avoid subsidies for local monopolists and any associated market inefficiencies. This is the focus of the discussion below. First, however, note that there are other effects of zonal aggregation related to equity concerns or the peculiar features of the California market. In actually animating the California policy, these may be more important than any economic arguments about the incentive effects in the market itself.

In the case of the equity motivation, for instance, it is would seem clear that the zonal model would have the effect of averaging prices across a larger region and, at least, would reduce prices in the high price region. This would be especially important in San Francisco, which is well known as an inactive zone where local market power is a concern. As we shall see, even this price moderation prediction is not necessarily true. Nevertheless, if this is the argument for zonal aggregation then it would be useful to examine the costs of this cost allocation policy in terms of the incentive effects and the subsidy to local monopolists.

Furthermore, it is important to make a distinction between real expansion of the transmission network and zonal aggregation. Real expansion of the network removes transmission constraints and expands competition. By contrast, administrative aggregation into a zone does nothing by itself to eliminate the transmission constraints. The incentive and market effects of real grid expansion are quite different from those of administrative cost reallocation.

At a minimum, therefore, it would be useful to understand better the market incentive effects of zonal aggregation in the face of local market power. If aggregation is important for other reasons, it would help to understand the costs of aggregation when there is market power. More likely, however, the motivation for aggregation into administrative zones is driven by an implicit assumption that this helps mitigate the power of the monopolist to extract greater rents.

> When a transmission path within a zone is regularly congested, there are good reasons to create a new zone. This transforms an zonal interface into an inter-zonal interface: doing so allows congestion over this interface to be handled using market processes based on adjustment bids (as opposed to the ISO's procedures for handling intra-zonal congestion). However, creating a new zone can lead to highly concentrated ownership of generation units in the markets within each zone, which enhances the ability of generation units owners to set high zonal prices. In light of this tradeoff, it is not the case that creating more zones always or typically enhances the efficiency of the overall market. Recognizing this tradeoff, the ISO Tariff calls for the creation of new zones only if generation markets on both sides of the interface in question are 'workably competitive.'[8]

[8] Frank A. Wolak, Chairman, Market Surveillance Committee of California Independent System Operator, "Report of Redesign of California Real-Time Energy and Ancillary Services Markets," October 18, 1999, p. 16.

This is not an isolated or unusual argument,[9] but it is especially pervasive and important in the California context. As we shall see, there are several issues here. First, there is the effect on the monopolist and its ability to increase its profits and set high zonal prices. These are different effects, and we shall see that the zonal aggregation always increases the ability to extract higher profits, and under reasonable assumptions zonal aggregation also enhances the ability of the monopolist to set higher prices. The efficiency effects of zonal aggregation are more complex, but dynamic efficiency is almost surely impaired by zonal aggregation and, again under a set of reasonable conditions, we find that zonal aggregation would reduce static efficiency. The somewhat counterintuitive combination of higher monopoly profits and greater static efficiency under the zonal model is not ruled out here, but the analysis shows the particular supply and demand conditions that would be necessary for this outcome.

If we are interested in markets and efficiency, therefore, the weight of the argument is that zonal aggregation enhances market power. For supporting a market, zone splitting and nodal pricing would be necessary to move in the direction of getting the prices right.

> …the success of the California market design requires aligning as closely as possible the generator's financial incentives for supplying energy in real-time with the ISO's desire to maintain system reliability at least cost.[10]

Finally, the choice between zonal and nodal approaches should be addressed as part of a package of other mitigation measures to reduce market power. One without the other would misguide the comparison. As we shall see, the scope of possible mitigation measures is actually expanded by getting the prices right.

III. The Setting

If a generator has locational market power, it will be able to profitably raise the price at which it offers power to the market above the competitive level whether congestion is managed using zonal pricing, inter-zonal pricing or nodal pricing. If locational market power exists, zonal pricing is not superior to nodal pricing or inter-zonal pricing in limiting the exercise of that market power. Splitting a zone into two or more zones when zonal congestion exists can lead to a more efficient outcome and better discipline the exercise of market power, if it exists, than relying on zonal congestion management systems.[11]

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[9] For example, see Alex Henney, "Contrasts in restructuring Wholesale Electric Markets: England/Wales, California and the PJM," The Electricity Journal, August/September 1998, p. 35.

[10] Frank A. Wolak, Chairman, Market Surveillance Committee of California Independent System Operator, "Report of Redesign of California Real-Time Energy and Ancillary Services Markets," October 18, 1999, p. 17.

[11] In the radial framework used to explain zonal principles, the problems of loop flow do not arise. Here we treat splitting a zone with two locations and nodal pricing as equivalent. If the zonal assumption

Moreover, in a considerable variety of circumstances nodal pricing and inter-zonal pricing would be far more effective in limiting the exercise of market power than would be zonal pricing. Of course, zonal pricing combined with effective market power mitigation could result in a more efficient outcome than nodal or inter-zonal pricing without effective market power mitigation, but that difference would be due to the difference in mitigation, not a difference in the pricing systems. On an apples to apples basis, nodal pricing and inter-zonal pricing can result in either the same or a more competitive outcome than zonal congestion pricing, if market power is either present and mitigated or unmitigated. The appropriate comparison is between zonal and nodal or inter-zonal pricing with unmitigated market power and between zonal and nodal or inter-zonal pricing with mitigated market power.[12]

There are at least four reasons why nodal pricing is often superior to zonal pricing from a competitive standpoint when the potential for the exercise of locational market power exists. The first three reasons are also reasons for the superiority of inter-zonal congestion management over zonal congestion management in these circumstances. First, zonal pricing can create market power in the hypothetical zonal dispatch that does not exist in the actual power market under either nodal or inter-zonal pricing. Second, zonal pricing can create market power in the zonal redispatch that does not exist in the actual power market under either nodal or inter-zonal pricing. Third, by reducing the response of demand in the constrained region to the exercise of locational market power, zonal pricing can make profitable the exercise of market power that would be unprofitable under either nodal or inter-zonal pricing. Fourth, the zonal pricing and redispatch mechanism can reduce the supply elasticity of energy across open interfaces, making profitable the exercise of market power that would be unprofitable under nodal pricing.

Nodal pricing is also superior to zonal pricing when the potential for the exercise of locational market power exists, because nodal pricing permits the use of financial instruments such as Contracts For Differences (CFDs), Transmission Congestion Contracts (TCCs) and price contingent TCCs as mechanisms to mitigate the locational market power. These financial instruments are not available as mitigation mechanisms for zonal congestion pricing, precisely because financial commitments under zonal pricing are not location specific and thus cannot provide the seller with the financial

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of a radial network does not apply, the equivalence may not hold and there would be further problems associated with zonal aggregation.

[12] Some of the peculiar features of the California market, such as individual load balancing requirements, can complicate the application of market power mitigation strategies such as call contracts. These load balancing requirements, however, are not maintained during intra-zonal congestion management and need not stand in the way of using call contracts to manage inter-zonal congestion. Since these features tend to increase transaction costs and reduce the efficiency of the market, the policy of resisting zonal separation in the presence of local market power should be addressed on its own merits, rather than used to incur additional costs to protect inefficient market designs.

incentive to supply power at the location required to mitigate market power.[13]

These properties of nodal and zonal pricing are illustrated below first through a simple example with a flat supply curve at each of two radially connected locations that compose a zone. The example is then modified to include an upward sloping supply curve for energy at each of the two locations. Next, the example is extended to include both upward sloping supply curves and downward sloping demand curves. Finally, the example is extended to a transmission system with three locations and three lines (i.e. a network with parallel flows). These examples were selected to encompass the kinds of issues expected in realistic markets. In all of these examples, it is seen that nodal pricing, or splitting zones to reflect congestion, results in an outcome that is at least as efficient and competitive as under zonal pricing with zonal congestion management, and that there are circumstances in which zonal congestion pricing can result in less efficient and competitive outcomes than would prevail under nodal pricing, or if the zone were split.

In an appendix, we take up the problem of characterizing the market outcomes in the presence of local market power. The basic conclusion supports the implications of the examples. The use of zonal pricing subsidizes the monopolist, and creates incentive problems that will create pressure for other interventions in the market. Although it may be possible to design examples where zonal pricing both subsidizes the monopolist and improves static efficiency, the long-run effects and the weight of the argument point to the preference for nodal pricing and its accompanying tools as a better way to mitigate market power.

IV. Flat Supply and Inelastic Demand

Consider a market with two radially connected nodes, Node 1 and Node 2. It is assumed that there is a price inelastic demand of 8000 MW at node 1 and 2000 MW at node 2. There is also 10,500 MW of generation at node 1 with an incremental cost of \$20, and 2000 MW of generation at node 2 with an incremental cost of \$30. We begin by solving for the competitive equilibrium under nodal and single zone pricing if all of the generation is owned by entities with insignificant ownership positions. The nodal case also illustrates the effects of splitting a zone and using inter-zonal pricing to manage congestion. We will then show how this equilibrium changes under both nodal (or inter-zonal) and zonal congestion pricing if the generation at node 2 is owned by a single entity and is not subject to any form of market power mitigation. Finally, we will describe the equilibrium under nodal and zonal pricing if the generation at node 2 is subject to a market power mitigation contract.

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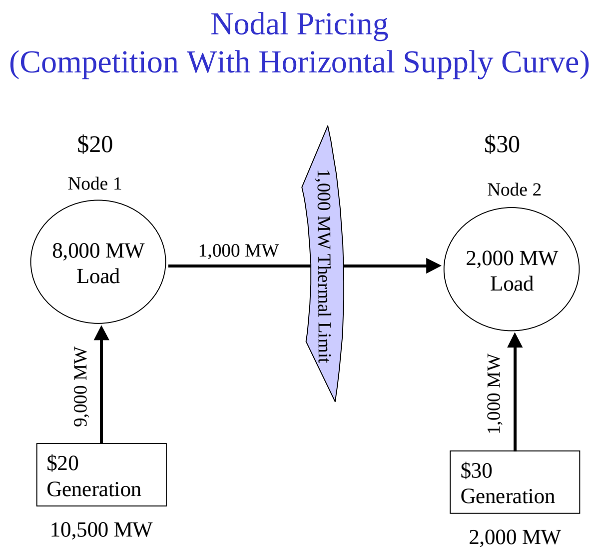
[13] The potential for the mitigation of locational market power through financial instruments is not the focus of this note but is briefly discussed below. The advantages of market power mitigation through financial instruments under nodal pricing include: 1) insulating the broad market from the impact of flawed regulatory measures of the incremental cost of the generators subject to mitigation; 2) preserving market incentives for load management, conservation and distributed generation to compete with the generators subject to mitigation; and 3) providing a price signal and price incentives for transmission projects that would compete with the generation subject to mitigation.

A. Competitive Market Equilibrium

1. Nodal Congestion Pricing

In a pricing system based on least-cost dispatch and nodal pricing, price taking generators at nodes 1 and 2 would find it profitable to offer their supply into the market at incremental cost.[14] Based on these bids, the least-cost dispatch and competitive equilibrium would be to dispatch the low cost generation at node 1 to meet the load at nodes 1 and 2 until the transmission constraint between node 1 and 2 became binding. The remaining load at node 2 would be met with the higher cost generation located at Node 2. The total as bid cost of meeting load would be $210,000 and the price of power would be $20 at node 1 and $30 at node 2, see Figure 1.[15]

Figure 1



The system operator's congestion pricing would collect $10,000 of congestion rents that could directly or indirectly offset the transmission cost of service.[16] Total net payments by loads would be $210,000, see Table 2. Although the load at both nodes 1 and 2 has

14 The least-cost dispatch with nodal pricing corresponds to the competitive equilibrium.

15 $20 * 9000MW at node 1 + $30 * 1000MW at node 2 = $210,000.

16 The gross payments by load would be $220,000 (8000MW * $20 + 2000MW*$30) see Table 2. The congestion rents would be the difference between the gross payments by load ($220,000) and payments to generators $210,000 (9000MW * 20 + 1000MW * 30). In this simple example, the congestion rents are equal to the power transferred from node 1 to node 2 times the difference in prices between nodes 2 and node 1.

been assumed for the purpose of the example to be completely price inelastic, it should be noted that with nodal pricing, the prices at each location reflect the incremental cost of power at that location and therefore provide generators with efficient locational incentives, provide loads with efficient substitution incentives, and the price differential between nodes 1 and 2 provides a price signal and incentive for incremental transmission expansion projects.

Table 2

Cost To Load
Competition With Horizontal Supply Curve

	Nodal Pricing		Zonal Pricing	
	Price	**Payments**	**Price**	**Payments**
Node 1	$20	$160,000	$20	$160,000
Node 2	$30	$60,000	$20	$40,000
Total		$220,000		$200,000
-Congestion Rent Credits		-$10,000		0
Constrained On/Off Payments		0		$10,000
Net Payments		$210,000		$210,000

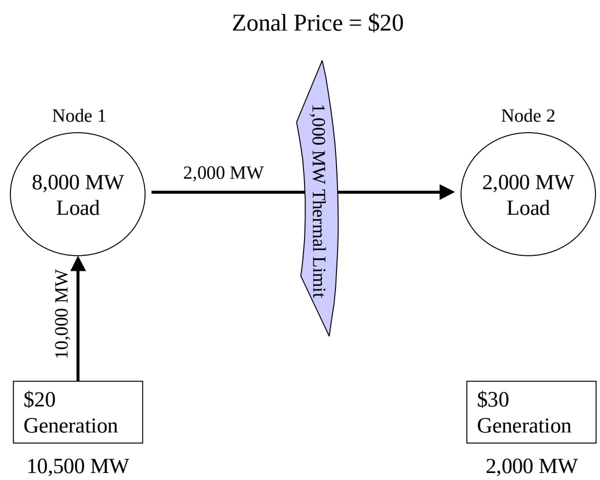
The description of nodal pricing in Figure 1 and Table 2 also describes the operation of an inter-zonal congestion pricing system if node 1 and node 2 are zones.

2. Zonal Congestion Pricing

In a pricing system based on least-cost dispatch and zonal congestion management for a zone that includes nodes 1 and 2, competitive generators would again find it profitable to offer their output into the market at incremental cost. Based on these bids, the least cost zonal dispatch and competitive equilibrium would be to dispatch the low cost generation at node 1 to meet the entire load in the zone and the zonal price would be $20. This generation schedule, however, would violate the transmission limit between nodes 1 and 2, requiring use of the system operator's zonal congestion management scheme, see Figure 3.

Figure 3

Unconstrained Zonal Dispatch
Competitive Market With Horizontal Supply Curve



Again assuming competition, under a California/UK style intra-zonal congestion management system with constrained on and off payments, the generators at node 1 would not require any constrained off payments to reduce their output because the zonal price would equal their incremental generating costs. The system operator would also need to constrain on 1000MW of generation at node 2 at a price of $30.[16.1] The resulting dispatch would be the same as shown in Figure 1. The total cost as bid of meeting load would again be $210,000 (the same units are meeting load with the same as bid cost as under nodal pricing). Under zonal pricing, however, the zonal price would be $20 for customers located at both node 1 and node 2. Loads would also pay the cost of the constrained on payments in the form of uplift (uplift = $1/MW, $10,000/10,000MW) and no congestion rents would be collected for crediting against the transmission cost of service. The net total payments by load would therefore total $210,000 as shown in Table 2, which is identical to the net total payments under nodal pricing.

In such a competitive market, the only difference between nodal and zonal congestion pricing is in the incidence of the congestion costs. Under nodal pricing, the higher cost of meeting load at node 2 is borne by loads located at node 2, while under zonal congestion pricing the higher cost of meeting load at node 2 is shared by all of the loads in the zone.

[16.1] Thus, the system operator would incur out of merit redispatch costs of $10,000 = ($30 - $20) * 1000.

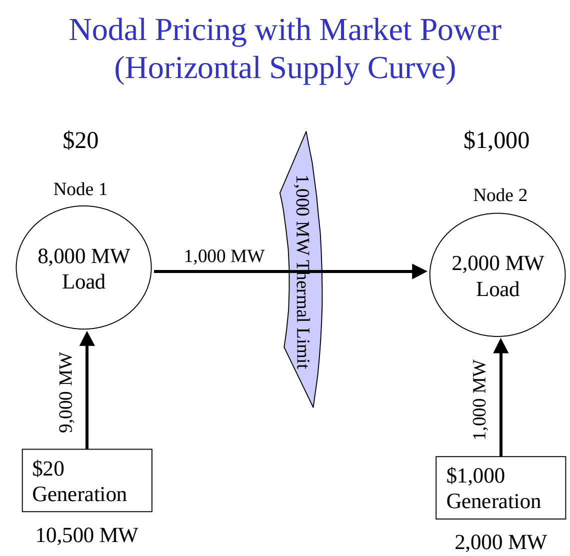
B. Unmitigated Market Power

We now reanalyze the same electric system, but assume that the generation at node 2 is owned by a single entity that bids the output of these generators into the market at a price of $1000. This might occur because of a cap on bids or prices. In any event, some such limit must be assumed for the example with perfectly inelastic demand to avoid the outcome of infinitely high prices. See the appendix for an analysis with some demand elasticity and no price caps.

1. Nodal Congestion Pricing

In a pricing system based on least-cost dispatch and nodal pricing, competitive generators at node 1 would still find it profitable to offer their generation into the spot market at their incremental cost. The generator at node 2 is now assumed, however, to bid its output into the market at $1000/MW which is far above its costs. Based on these bids, the least-cost dispatch would be to dispatch the low cost generation at node 1 to meet the load at nodes 1 and 2 until the transmission constraint between node 1 and 2 became binding. The remaining load would be met with the higher cost generation at Node 2. The total as bid cost of meeting load would now be $1,180,000[17] and the price of power would be $20 at node 1 and $1000 at node 2, see Figure 4.

Figure 4



The system operator's congestion pricing would collect $980,000 of congestion rents that

[17] $20 * 9,000 MW + $1,000 * 1,000 MW = $1,180,000.

would be used to directly or indirectly offset the transmission cost of service. [18] Net total payments by loads would therefore be $1,180,000, of which $1,000,000 would go to the generator with market power at node 2, see Table 5. As before, although the load at both nodes 1 and 2 has been assumed for the purpose of the example to be completely price inelastic, under nodal pricing the prices paid by loads and to generators at each location reflect the incremental "as bid" cost of meeting load at that location and therefore provide new generators with efficient locational incentives, provide loads with efficient substitution incentives, and the price differential provides a price signal and incentive for incremental transmission expansion projects.

Table 5

Cost To Load
Horizontal Supply Curve and Market Power

	Nodal Pricing		**Zonal Pricing**	
	Price	**Payments**	**Price**	**Payments**
Node 1	$20	$160,000	$20	$160,000
Node 2	$1,000	$2,000,000	$20	$40,000
Total		$2,160,000		$200,000
Congestion Rent Credits		$980,000		0
Constrained On/Off Payments		0		$980,000
Net Payments		$1,180,000		$1,180,000

As before, node 1 and node 2 could also be thought of as zones, and the example then illustrates the operation of inter-zonal congestion pricing when there is not workable competition in one of the zones.

2. Zonal Congestion Pricing

In a pricing system based on least-cost dispatch and zonal pricing for a zone that includes nodes 1 and 2, competitive generators located at node 1 would again find it profitable to bid their energy into the market at their incremental cost. Based on these bids, the least cost unconstrained dispatch and competitive equilibrium would be to dispatch the low cost generation at node 1 to meet the entire load in the zone and the zonal price would be $20, just as in Figure 3. This generation schedule, however, would violate the

[18] The congestion rents are again equal to the difference between the gross payments by load (8000MW*$20/MW + 2000MW*$1000/MW = $2,160,000) and total payments to generators (9000MW*$20 + 1000MW*$1000 = $1,180,000).

transmission limit between nodes 1 and 2, requiring use of the system operator's zonal congestion management scheme. Again assuming competition, the generators at node 1 would not require any constrained off payments because the zonal price would equal their incremental running cost, but the system operator would need to constrain on 1000MW of generation at node 2 at a price of $1000/MWh. The resulting dispatch would be the same as shown in Figure 4 but the zonal price of power would be $20 every where. Because of the very large constrained on payments to the generator with market power, the total as bid cost of meeting load would be $1,180,000. The as bid cost of meeting load is the same under nodal and zonal congestion pricing because the same resources are dispatched to meet load and they have the same bidding incentives. Under zonal congestion pricing the zonal price would be $20 for customers located at both node 1 and node 2, but there would also be constrained on payments of $98/MW ($980,000/10,000MW) and no congestion rents would be collected for crediting against the transmission cost of service. The net total payments by load would total $1,180,000 as shown in Table 5, which is identical to the total net payments under nodal pricing.

It is noteworthy that although demand is inelastic by assumption, load throughout the zone would have an incentive to reduce consumption under zonal pricing because the total cost of power would be $118/MW, but only consumption reductions by loads at node 2 would actually reduce energy purchases from the firm with market power.

3. Comparison

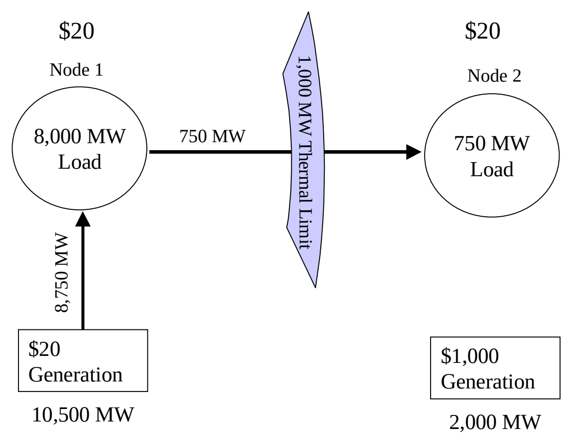
In this simple example, the generator at node 2 possesses market power and is able to exercise that market power under either zonal, inter-zonal or nodal congestion pricing. Moreover, the total cost of power to load is the same under nodal, inter-zonal and zonal congestion pricing.

The reason why nodal (or inter-zonal) congestion pricing cannot make things worse from a competition standpoint than they would be under zonal congestion pricing when locational market power exists, is that the system operator must pay the monopoly price for the required quantity of power at node 2 under any market based pricing system. This outcome is a consequence of the transmission constraint, not the pricing system. In this regard it is important not to confuse a shift in the incidence of market power with mitigation of market power. In the example portrayed in Figure 4 and Table 5, the price charged for power to loads at node 2 is markedly lower under zonal congestion pricing ($20 plus $98 uplift) than under nodal congestion pricing ($1000). This is not a benefit of zonal congestion pricing, however, because a correspondingly higher price is charged to the loads at node 1 under zonal congestion pricing ($118 under zonal congestion pricing vs. $20 under nodal pricing). Loads located at node 2 might prefer zonal congestion pricing because much of the cost of the exercise of market power would be shifted onto consumers at node 1, but this shift in incidence does not mitigate the market power, and can, as shown below in the context of downward sloping demand curves, exacerbate market power.

It is also important not to confuse the competitive impact of nodal, inter-zonal and zonal congestion pricing with the impact of binding transmission constraints and the extent of the market. Thus, the market for energy at node 2 would be more competitive under either pricing system if load at node 2 were only 750 MW, as then the transmission constraint would not be binding and load at node 2 could be met entirely with generation at node 1, see Figure 6. The relevant market would then be zonal, and a monopoly generator located at node 2 would lack market power at node 2 under either nodal, inter-zonal/or zonal congestion pricing systems, because there would be no congestion. This hypothetical merely shows that zonal congestion pricing works when one does not use it, not that zonal congestion pricing is efficient or procompetitive.

Figure 6

Nodal or Zonal Congestion Pricing
Horizontal Supply Curve and No Constraint



The issue in choosing between nodal (or inter-zonal) and zonal congestion pricing, is not whether a broader market reduces the scope for the exercise of market power, but whether market power is reduced by calculating prices as if the market is broad when it is not (i.e., using zonal pricing when intra-zonal congestion exists). As discussed above, the answer to this second question is “no”.

Even for the simple example discussed above, zonal congestion pricing can lead to less efficient outcomes than nodal or inter-zonal congestion pricing in some circumstances in which locational market power exists and congestion is present. This potential exists because zonal congestion pricing rules can create market power in the hypothetical unconstrained dispatch and zonal redispatch that does not exist in the real power market and dispatch. That is, zonal congestion pricing in essence gives rise to multiple steps in the price determination process in which market power may be exercised. The step common to nodal and zonal congestion pricing is the determination of the cost of meeting load based on the actual transmission constraints. The potential for the exercise of locational market power in this step is the same between zonal and nodal congestion pricing systems, because both systems ultimately must respect the real limits of the transmission grid.[19] Zonal congestion pricing systems, however, also include some kind of hypothetical unconstrained dispatch step, and a redispatch step, and it is possible for market power to exist in these steps that would not exist in the actual power market and dispatch.

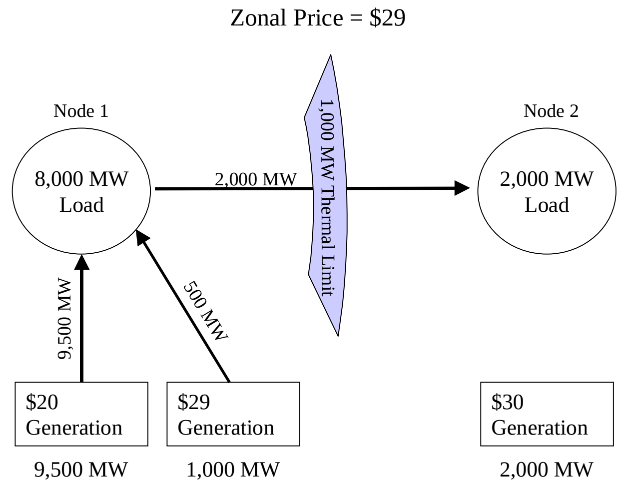
The possibility that zonal pricing will give rise to market power in the hypothetical zonal dispatch step can be illustrated with the simple example discussed above by considering the case in which 1000MW of the $20 generation located at node 1 is owned by a single entity. Under nodal (or inter-zonal) congestion pricing, the ownership and bidding strategy of this generation would be irrelevant in the hour considered whether the generation at node 2 were competitive (Figure 1) or monopolistic (Figure 4), because there would be more than enough competitively bid generation at node 1 (9500MW) to meet load at node 1 and supply 1000MW of energy to node 2. Under zonal congestion pricing, however, common ownership of 1000MW of generation at node 1 could allow that generation owner to exercise market power in the hypothetical dispatch, as illustrated below.

Consider first the case in which the generation market at node 2 is competitive and energy is bid into the market at node 2 for $30/MW. If 1000MW of generation located at node 1 were owned by a single entity, that owner could bid that capacity into the market at $29/MW as shown in Figure 7, raising the zonal price in the hypothetical zonal dispatch to $29/MW plus uplift.

[19] The potential for the exercise of market power would of course be increased by the application of restrictions on transmission flows beyond those required to maintain reliability.

Figure 7

Zonal Congestion Pricing Creates Market Power at Node 2
Unconstrained Zonal Dispatch



The total net cost to loads would in these circumstances be materially higher under zonal pricing than under nodal pricing (see Table 8)[20] because the zonal pricing would have created market power (in the unconstrained zonal dispatch step) that would not otherwise exist.

[20] The constrained on and off payments shown in Table 28 are $10/MW because the generation located at node 1 would submit real time decremental bids of $20/MW while the generation located at node 2 would submit incremental bids of $30.

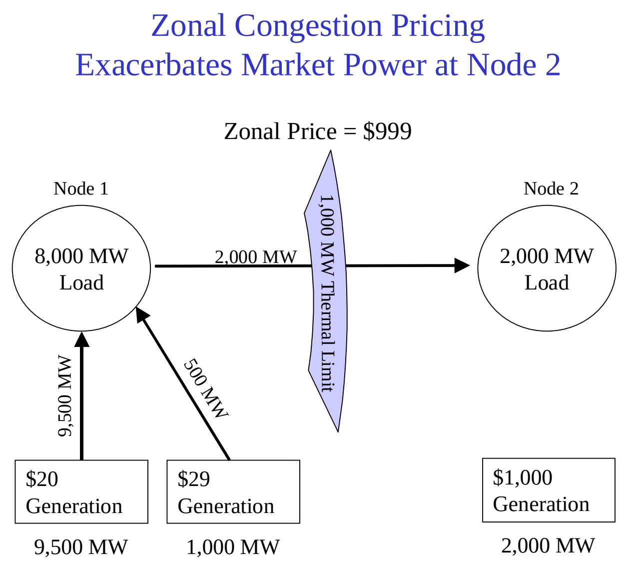
Table 8

Cost To Load
Market Power At Node 1 In Hypothetical Dispatch

	Nodal Pricing		Zonal Pricing	
	Price	Payments	Price	Payments
Node 1	$20	$160,000	$29	$232,000
Node 2	$30	$60,000	$29	$58,000
Total		$220,000		$290,000
Congestion Rent Credits		$10,000		0
Constrained On/Off Payments		0		$10,000
Net Payments		$210,000		$300,000

The impact under zonal congestion pricing of common ownership of 1000MW of the generation located at Node 1 would be even more extreme if the generation market at node 2 were non-competitive and the generation at node 2 were offered into the market at $1000/MW. In such a situation, the 1000MW of commonly owned generation at node 1 could be offered into the market at $999/MW, raising the zonal market price determined by the hypothetical zonal dispatch to $999/MW plus uplift, see Figure 9.

Figure 9



In this case, the total net cost to load would be far higher under zonal congestion pricing than under nodal or inter-zonal congestion pricing, because the zonal congestion pricing would greatly exacerbate the impact of the market power at node 2, creating market power in the hypothetical zonal dispatch that would not exist in the real power market.

Table 10

Cost To Load
Market Power At Node 2

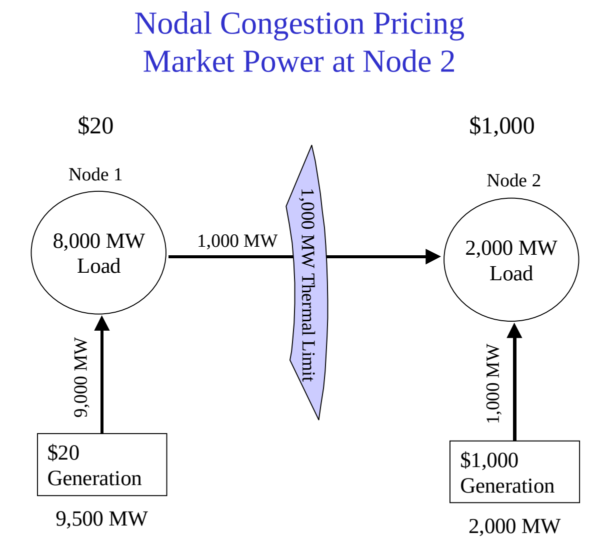
	Nodal Pricing		Zonal Pricing	
	Price	**Payments**	**Price**	**Payments**
Node 1	$20	$160,000	$999	$7,992,000
Node 2	$1,000	$2,000,000	$999	$1,998,000
Total		$2,160,000		$9,990,000
- Congestion Rent Credits		$980,000		0
Constrained On/Off Payments		0		$980,000
Net Payments		$1,180,000		$10,970,000

Not only would all loads in the zone pay a zonal price of $999/MW, but loads would pay an additional $98/MW in constrained on and off payments.[21]

In fact, zonal congestion pricing could exacerbate the impact of the exercise of market power at node 2 through its impact on the hypothetical dispatch even if the generator at node 2 were the only entity in the market with market power. This is seen in Figures 11 and 12. In these figures it is assumed that there is only 9500 MW of generation at Node 1, and 2000 MW of commonly owned generation at node 2. The commonly owned generation at node 2 would be able to exercise its locational market power under nodal (or inter-zonal) congestion pricing, raising the price at Node 2 to $1000/MW, while the price at Node 1 would remain at $20/MW, as shown in Figure 11.

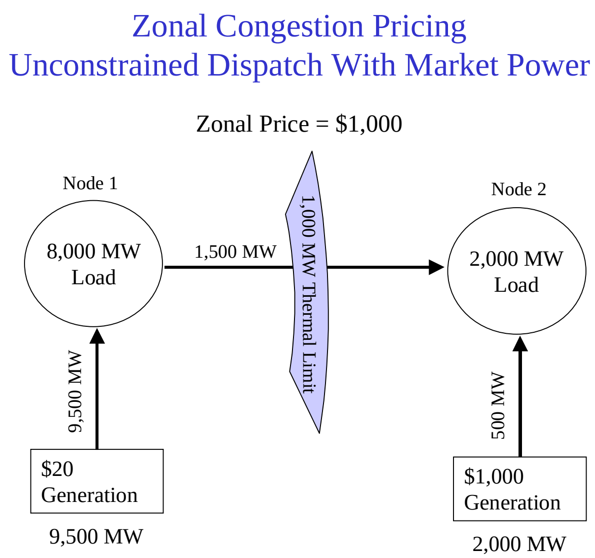
[21] Generators at node 1 would require constrained off payments of $979/MW ($999-$20), on 1000 MW of generation reflecting their margin on sales at the zonal price, while generators at node 2 would require $1 of constrained on payments on 1000 MW of generation.

Figure 11



Under zonal congestion pricing, however, the hypothetical zonal price would be determined by the generation at Node 2, and the exercise of market power by the entity owning generation at node 2 would raise the zonal price for load at both nodes to $1000/MW, plus uplift.

Figure 12



Zonal transmission pricing can also give rise to market power in the zonal redispatch in circumstances in which no entity has market power in the actual power market. This can be illustrated by modifying the example portrayed in Figure 6 by assuming that the generator at node 2 has an incremental generating cost of $20 rather than $30. As discussed above, the generator at node 2 could not raise the price at node 2 above $20 under either a zonal or nodal pricing system because at any price above $20, its output would be displaced by imports.

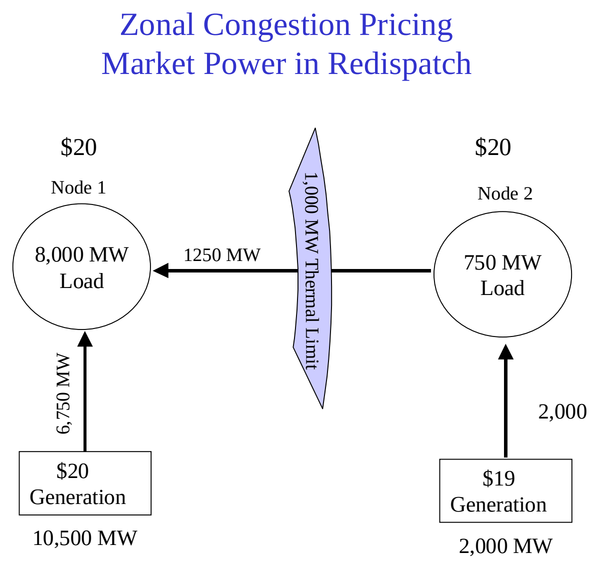
Under a nodal pricing system, if the generator at node 2 bid its output into the market at any price below $20, it would be dispatched for 1750 MW and its bid would set the price at node 2. This would be unprofitable, because the price at node 2 would be less than the generator's incremental costs.[22] Regardless, the generator at node 2 would not be scheduled to generate more than 1750 MW because the system operator would take account of the 1000MW limit on the line 2-1 in its dispatch.

Under a zonal pricing system, however, there is a potential for the generator at node 2 to exercise market power in the zonal redispatch.[23] If this generator were to bid its output into the zonal market at less than $20/MW, the unit would be scheduled to generate 2000 MW in the zonal dispatch as shown in Figure 31, and the zonal price would be $20/MW (set by generators at node 1). This generation schedule, however, would violate the transmission limit between nodes 1 and 2, requiring use of the system operator's zonal congestion management scheme.

[22] Because the generator at node 2 would be the only seller at node 2, if its incremental generating costs were less than $20/MW it would still not find it profitable to offer its output into the market at any price less than $20/MW so as to avoid depressing the price at node 2 below $20

[23] Frank A. Wolak, Chairman, Market Surveillance Committee of California Independent System Operator, "Report of Redesign of California Real-Time Energy and Ancillary Services Markets," October 18, 1999, p. 104.

Figure 31



Once scheduled to generate 2000 MW at node 2 under a zonal pricing system, the supplier at node 2 would be able to exercise market power by offering intra-zonal redispatch to relieve congestion on the line from node 2 to node 1 at a price of -$1000, that is, the generator would require a payment of $1000/MW to reduce output. Since this supplier is the only generator at node 2, it would be the monopoly seller of redispatch services, and the ISO would be forced to purchase intra-zonal redispatch from this entity. Thus, in the example above, zonal pricing enables the generator at node 2 to bid so as to create intra-zonal congestion and force the ISO to buy 250 MW of redispatch from the generator at node 2 at $1000/MW at a cost of $250,000, as well as 250 MW of energy at node 1 at $20. In these circumstances, uplift would exceed the cost of power as shown in Table 32.

Table 32

Cost To Load
Market Power At Node 2 In Zonal Redispatch

	Nodal Pricing		**Zonal Pricing**	
	Price	**Payments**	**Price**	**Payments**
Node 1	$20	$160,000	$20	$160,000
Node 2	$20	$15,000	$20	$15,000
Total		$175,000		$175,000
Congestion Rent Credits		0		0
Constrained On/Off Payments		0		$255,000
Net Payments		$175,000		$430,000

C. Mitigated Market Power

We now reanalyze the same system with a market power mitigation system in place. We again assume that the generation at node 2 is owned by a single entity but it is now also assumed that the entity owning generation at node 2 is subject to a call contract at $30.

1. Nodal Congestion Pricing

In a pricing system based on least-cost dispatch and nodal congestion pricing, competitive generators at node 1 would find it profitable to bid their costs. The generator at node 2 would absent mitigation possess the ability to raise the price of power at node 2 by withholding output at competitive prices (i.e. raising its bid), but this potential market power is eliminated by the call contract which enables the ISO to dispatch the generation at node 2 at a price of $30. [24] Based on these bids and call contracts, the least-cost dispatch would be to dispatch the low cost generation at node 1 to meet the load until the transmission constraint between node 1 and 2 became binding. The remaining load would be met with the higher cost generation at Node 2 that is subject to the call contract at $30. The total as bid cost of meeting load would be $210,000 and the price of power would be $20 at node 1 and $30 at node 2, just as in Figure 1. The system operator's

[24] Nodal pricing also makes possible reliance on a variety of financial instruments to mitigate market power such as CFDs with the generator at node 2, assignment to the generator at node 2 of conventional node 2 to node 1 TCCs or the assignment to the generator at node 2 of a price contingent node 2 to node 1 TCC.

congestion pricing would collect $10,000 of congestion rents that would directly or indirectly offset the transmission cost of service. Net total payments by load for power would therefore be $210,000 just as in the competitive case, see Table 2.

The outcome of the pricing system would again be the same if nodes 1 and 2 were zones and inter-zonal congestion pricing were used to manage congestion. The exercise of market power would be precluded by the ISO's ability to exercise the call contract at $30.

2. Zonal Congestion Pricing

In a pricing system based on least-cost dispatch and zonal congestion pricing for a single zone that includes nodes 1 and 2, competitive generators at node 1 would find it profitable to offer their output to the market at incremental cost. Based on these bids, the least cost unconstrained dispatch would be to dispatch the low cost generation at node 1 to meet the entire load in the zone and the zonal price would be $20. As before, this generation schedule would violate the transmission limit between nodes 1 and 2, requiring use of the system operator's zonal congestion management scheme. Again assuming competition among the generators at node 1, these generators would not require any constrained off payments to reduce output because the zonal price would equal their incremental cost. The system operator would, however, need to constrain on 1000MW of generation at node 2 at the call contract price of $30/MWh. The resulting dispatch would be the same as shown in Figure 1 but the zonal price of power would be $20 everywhere. The total payments by load would be $210,000 as shown in Table 2, which is identical to the net payments under nodal congestion pricing.

3. Comparison

As illustrated by the example above, market power mitigation is possible under either nodal, inter-zonal, or zonal congestion pricing systems and the potential for mitigation of market power is not a unique advantage of zonal congestion pricing systems. Indeed, the reverse is true. Zonal congestion pricing systems severely limit the potential mechanisms for market power mitigation because mitigation based on financial instruments is not feasible. Among the financial instruments that could be used to mitigate market power under nodal congestion pricing would be the assignment to the generator at node 2 of 1000MW of contracts for differences with a $30 strike price for energy at node 2. The generator would have an incentive to generate energy whenever the price at node 2 exceeded its incremental generating costs, and could not benefit from withholding output or raising the price at node 2 above its incremental generating costs, because price increases would result in correspondingly higher payments to the CFD holder.

The approach of using financial instruments to mitigate locational market power is not available under zonal congestion pricing precisely because delivery obligations are nonlocational within the zone. Thus, if the generator owner at node 2 were assigned a 1000MW CFD under zonal congestion pricing, this would not affect the generator's incentive to withhold output because the withholding of output would not affect the zonal price but merely elevate uplift. Such a generator could decline to operate, make payments to the CFD holder based on the $20 zonal price, and force the system operator to pay out of merit costs to constrain it on in real time. A related problem under zonal congestion pricing is the inability to schedule congestion management in the day ahead market. The same incentive problem that would exist with CFDs exists with day ahead commitments. Under zonal pricing, a high cost generator scheduled day ahead to operate out of merit to provide congestion management could choose not to operate in real time and cover its day ahead commitment by purchasing power at the real time zonal imbalance price. The system operator would then need to pay for congestion management again in real time. This inability to schedule congestion relief day ahead may also contribute to the exercise of market power by reducing the options available to the system operator.[25]

Moreover, market power mitigation based on call contracts with generators at node 2 would not be sufficient to mitigate the potential market power that could be created by zonal pricing in either the hypothetical zonal dispatch or the zonal redispatch. Thus, zonal pricing could give rise to need for additional call contracts to mitigate market power, requiring expanded intervention in the generation market. For example, in the situation illustrated in Figure 7, mitigation of the market power in the hypothetical dispatch would require a call contract with the generator owning 1000 MW at node 1, even though this energy would actually not be needed to meet load. [26] Similarly, under zonal pricing, the system operator would not only need a call contract permitting it to dispatch energy from a monopoly generator at node 2 at a specified price, it would also need a put contract permitting it to sell back energy to a monopoly generator at node 2 at a specified price. [27]

[25] This is why the California ISO cannot manage zonal congestion in the day ahead market; generators scheduled day ahead to provide intra-zonal congestion management would only have the right incentives if imbalances were settled at nodal prices. See also, Frank A. Wolak, Chairman, Market Surveillance Committee of California Independent System Operator, "Report of Redesign of California Real-Time Energy and Ancillary Services Markets," October 18, 1999, p.102.

[26] This potential for the exercise of market power in the unconstrained region under zonal pricing is particularly noteworthy in the California context as it raises the question of whether price effects blamed by the ISO on the incentives of RMR generators within constrained areas might actually be attributable to market power created by zonal pricing in the hypothetical dispatch and possessed by non-RMR generators outside the constrained region.

[27] Thus, it is the application of zonal pricing to intra-zonal congestion and the ISO's refusal to split zones, not market power in actual power markets, that gives rise to the need for the put provisions in Amendment 23.

D. Conclusion

It is evident from the simple example above that in the case of vertical demand curves, horizontal supply curves and a simple radial system there is no circumstance in which nodal or inter-zonal congestion pricing would lead to a less competitive outcome than would prevail under zonal congestion pricing. Even in such a simple world, however, zonal congestion pricing can create market power or exacerbate the impact of existing market power and lead to large income transfers.

V. Upward Sloping Supply Curves

The preceding example is now modified by introducing a minimal amount of upward slope to the supply curves at node 1 and node 2. It is now assumed that there is 9500 MW of generation available at Node 1 at a price of $20 and 1000 MW available at a price of $22. At node 2, there is 750 MW available at $25 and another 1250 MW available at $30/MW, see Figure 13 below. As before, we begin by solving for the competitive equilibrium under nodal and zonal congestion pricing; that is, if all of the generation is owned by entities with insignificant ownership positions. We then show how this equilibrium changes under both nodal and zonal congestion pricing if the generation at node 2 is owned by a single entity that is not subject to any form of market power mitigation. Finally, we assess the impact of market power mitigation contracts on performance under nodal and zonal congestion pricing.

A. Competitive market

1. Nodal Congestion Pricing

In a pricing system based on least-cost dispatch and nodal or inter-zonal congestion pricing, competitive generators at nodes 1 and 2 would find it profitable to bid their output into the market at incremental cost. Based on these bids, the least-cost dispatch would be to dispatch 9000MW of the low cost generation at node 1 to meet the load at nodes 1 and 2 until the transmission constraint between node 1 and 2 became binding. The remaining load would be met with the higher cost generation at Node 2, 750 MW at $25 and 250MW at $30. The total as bid cost of meeting load would therefore be $206,250 and the market price of power would be $20 at node 1 and $30 at node 2, see Figure 13.[28] The system operator's congestion pricing would collect $10,000 of congestion rents that could directly or indirectly offset the transmission cost of service. Net total payments by loads would therefore be $210,000 the same as shown in Table 2.

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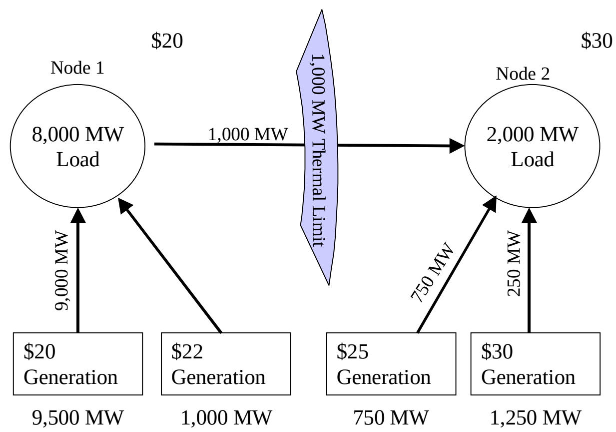
28 $20 * 9,000 MW + $25 * 750 MW + $30 * 250MW.

Figure 13

Nodal Congestion Pricing
(Competition With Upward Sloping Supply)

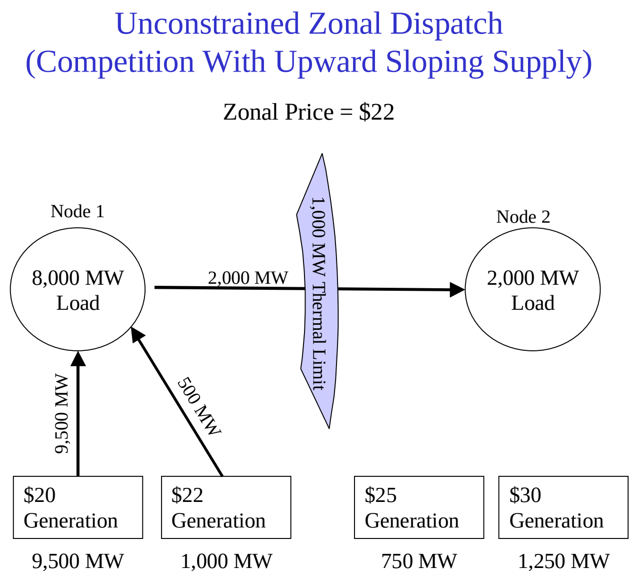


As before, neither the dispatch nor the pricing results would be changed if nodes 1 and 2 were zones and congestion between them were managed by an inter-zonal congestion pricing system.

2. Zonal congestion Pricing

In a pricing system based on least-cost dispatch and zonal congestion pricing for a single zone that includes nodes 1 and 2, competitive generators at node 1 would find it profitable to bid their costs. Based on these bids, the least-cost zonal dispatch would be to dispatch the low cost generation at node 1 to meet the entire load in the zone. With the assumed upward sloping supply curve, the zonal price would be $22 as shown by the hypothetical unconstrained dispatch in Figure 14. This generation schedule, however, would violate the transmission limit between nodes 1 and 2 (as also shown in Figure 14), requiring use of the system operator's zonal congestion management scheme.

Figure 14



Because the supply curve at node 1 is upward sloping the marginal generators located at node 1 would require constrained off payments in order to reduce generation; that is, sales of power at the $22 zonal price are incrementally profitable for the generators at node 1 with incremental generating costs of $20. Because it would be necessary to back down 500 MW of generation with incremental costs of $20 (as well as 500MW of generators with incremental costs of $22), in a competitive generation market the system operator would make constrained off payments of $2 *1000 MW.[29] In addition, the system operator would need to constrain on 1000MW of generation at node 2, and in a competitive generation market well informed generators at node 2 would offer redispatch at a price of $30.[30] The resulting dispatch would be the same as shown in Figure 13. The total as bid cost of meeting load would again be $206,250. Under the zonal congestion pricing system, however, the zonal price would be $22 for customers located

[29] In California terms, the system operator would sell power to the constrained off generators at $20 enabling them to cover their day ahead obligations to deliver for which they were paid $22. To the extent that the market model permits the system operator to act as a price discriminating monopsonist and informational advantages permitted the system operator to successfully price discriminate, the system operator could attempt to charge the low cost generators at node 1 their cost of $20 for replacement power and charge the higher cost generators at node 2 the higher $22 for replacement power. Such attempts at price discrimination are neither likely to be successful in the long run nor in the long-run interests of consumers, so the discussion in this paper assumes that all generators are paid the market clearing price for constrained off relief.

[30] Once again, to the extent that the market model permits the system operator to act as a price discriminating monopsonist and informational advantages permit the system operator to successfully price discriminate, the system operator could attempt to pay $25 for constrained on power from the low cost generators and to pay $30 for the marginal power at node 2. The discussion above assumes that all generators are paid the market price of power for constrained on energy.

at both node 1 and node 2, and there would be constrained on and off payments of $1MW (($2,000+ $8,000)/10,000MW), and no congestion rents would be collected for crediting against the transmission cost of service. The net total payments by load would therefore total $230,000 as shown in Table 15, compared to $210,000 under nodal or inter-zonal congestion pricing. The difference in the net total cost to load is attributable to the artificial inflation of the zonal price in the hypothetical dispatch.

Table 15

Cost To Load
Competition With Upward Sloping Supply

	Nodal Pricing		Zonal Pricing	
	Price	**Payments**	**Price**	**Payments**
Node 1	$20	$160,000	$22	$176,000
Node 2	$30	$60,000	$22	$44,000
Total		$220,000		$220,000
Congestion Rent Credits		-$10,000		0
Constrained On/Off Payments		0		$10,000
Net Payments		$210,000		$230,000

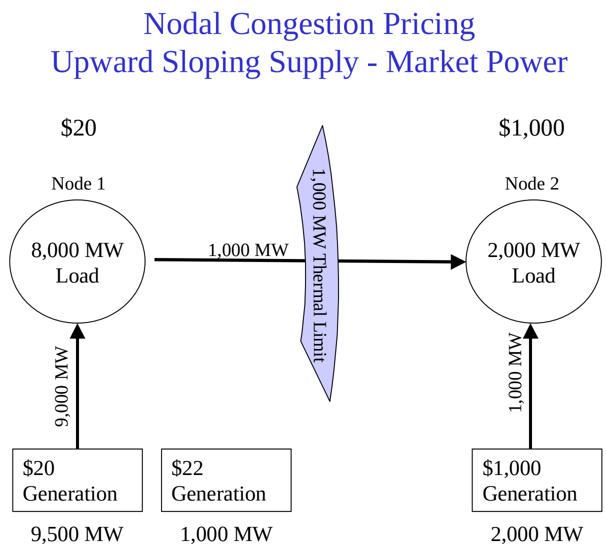
B. Unmitigated Market Power

We now reanalyze the same system, but assume that the generation at node 2 is owned by a single entity that offers its supply into the market at a price of $1000.

1. Nodal Congestion Pricing

In a pricing system based on least-cost dispatch and nodal congestion pricing, competitive generators at nodes 1 would still find it profitable to bid their output into the market at incremental cost. The generator at node 2 is now assumed, however to bid its output into the market at a much higher price, $1000/MW. Based on these bids, the least-cost dispatch would be to dispatch the low cost generation at node 1 to meet the load until the transmission constraint between node 1 and 2 became binding. The remaining load would be met with the higher cost generation at Node 2. The total as bid cost of meeting load would be $1,180,000 and the price of power would be $20 at node 1 and $1000 at node 2, see Figure 16.

Figure 16



The system operator's congestion pricing would collect $980,000 of congestion rents that could directly or indirectly offset the transmission cost of service. Total payments by loads would therefore be $1,180,000, of which $1,000,000 would go to the generator with market power at node 2, see Table 17. As before, although the load at both nodes 1 and 2 has been assumed for the purpose of the example to be completely price inelastic, under nodal pricing, the prices paid by loads and to generators at each location would reflect the incremental "as bid" cost of meeting load at that location and therefore would provide new generators with efficient locational incentives, provide loads with efficient substitution incentives, and the price differential would provide a price signal and incentive for incremental transmission expansion projects.

Table 17

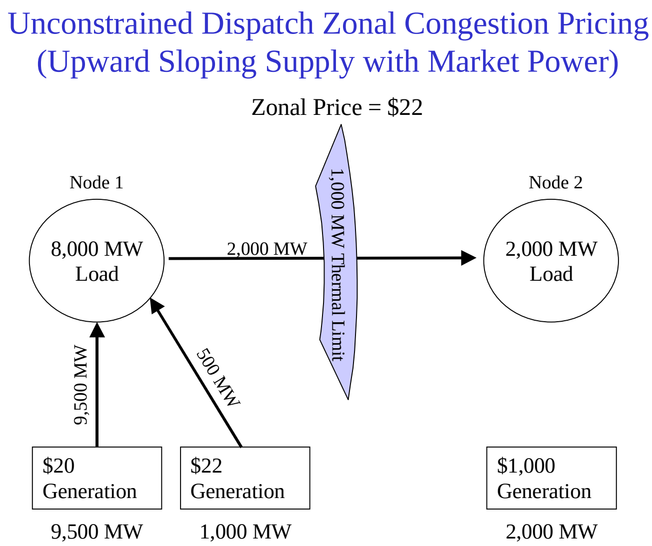
Cost To Load
Upward Sloping Supply with Market Power

	Nodal Pricing		Zonal Pricing	
	Price	Payments	Price	Payments
Node 1	$20	$160,000	$22	$176,000
Node 2	$1,000	$2,000,000	$22	$44,000
Total		$2,160,000		$220,000
Congestion Rent Credits		$980,000		0
Constrained On/Off Payments		0		$980,000
Net Payments		$1,180,000		$1,200,000

2. Zonal Congestion Pricing

In a pricing system based on least-cost dispatch and zonal congestion pricing for a single zone that includes nodes 1 and 2, competitive generators at node 1 would again find it profitable to bid their energy into the market at incremental cost. Based on these bids, the least cost unconstrained dispatch as shown in Figure 18 would be to dispatch the low cost generation at node 1 to meet the entire load in the zone and the zonal price would be $22. This generation schedule, however, would violate the transmission limit between nodes 1 and 2, requiring use of the system operator's zonal congestion management scheme.

Figure 18



Because it would be necessary to back down 500 MW of output of generators at node 1 with incremental generating costs of $20, the system operator again would make constrained off payments of $2 *1000 MW in a competitive generation market at node 1. In addition, the system operator would need to constrain on 1000MW of generation at node 2, and would therefore need to buy power from the assumed monopolist at node 2 at a price of $1000/MW. The resulting dispatch would be the same as shown in Figure 16. The total "as bid" cost of meeting load would again be $1,180,000. Under the zonal congestion pricing system, however, the zonal price would be $22 for customers located at both node 1 and node 2, there would also be constrained on and off payments of $98/MW (($2,000+ $978,000)/10,000MW) and no congestion rents would be collected for crediting against the transmission cost of service. The total payments by load would therefore be $120/MW totaling $1,200,000 as shown in Table 17, compared to $1,180,000 under nodal pricing. It is evident that market power could be exercised under either zonal or nodal congestion pricing systems. The only difference in the cost to loads in this situation would be the inflation of the zonal price from $20 to $22 due to the hypothetical zonal redispatch.

3. Comparison

It is evident in this instance that with the combination of market power and upward sloping supply curves, it is still the case that nodal or inter-zonal congestion pricing leads to an equilibrium that is no worse than under zonal congestion pricing. As in the case of the horizontal supply curve, zonal pricing could give rise to market power that would not otherwise exist if 1000MW of the generation located at node 1 were commonly owned, see Figure 18 above.

C. Mitigated Market Power

The potential for market power mitigation is also available under either nodal inter-zonal or zonal congestion pricing with the potential for mitigating market power through financial instruments existing under nodal pricing. Thus, a zonal congestion pricing system could mitigate market power by entering into call contracts at prices of $25 and $30 with the generators located at node 2, while similar results could be achieved under nodal or inter-zonal pricing through either call contracts or CFDs with strike prices of $25 and $30.

VI. Downward Sloping Demand Curve

The preceding example of a simple system is now modified by introducing a minimal amount of downward slope to the demand curves at node 1 and node 2. It is now assumed that the load at each node will be reduced by 1% at $50 and for every $50 increase in price above $50. The example is structured so that load is unchanged at the competitive level of prices from the earlier examples. The impact of price sensitive load is then evaluated under both nodal and zonal congestion pricing in the case in which generation at node 2 is able to exercise market power.

A. Competitive Market Equilibrium

This example has been constructed such that the price and output with competitive bidding are unchanged from the preceding example, see Figures 13 and 14 and Table 15.

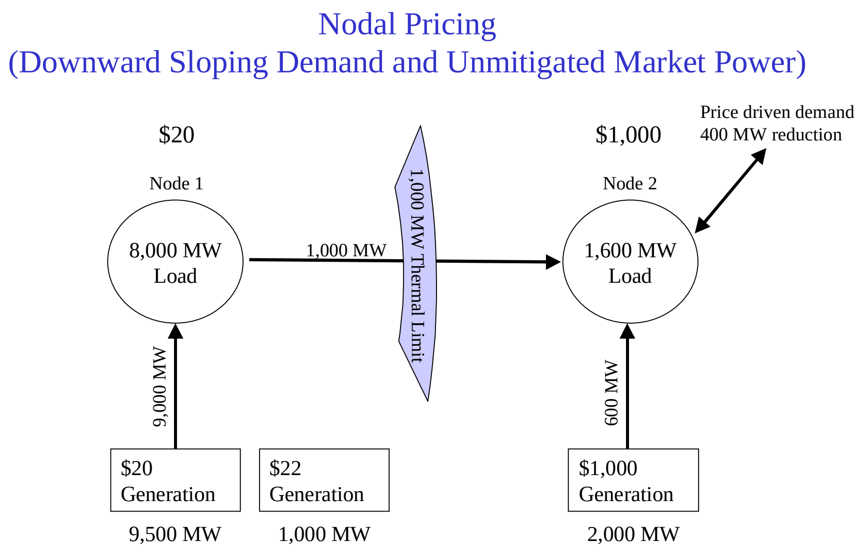
B. Unmitigated market Power

1. Nodal Congestion Pricing

In a pricing system based on least-cost dispatch and nodal or inter-zonal congestion pricing, competitive generators at nodes 1 would still find it profitable to offer energy into the market at incremental cost. The generator at node 2 is assumed to exercise market power and bid its energy into the market at $1000/MW. Based on these bids, the least-cost dispatch would be to employ the low cost generation at node 1 to meet the load at nodes 1 and 2 until the transmission constraint between node 1 and 2 became binding. The remaining load would be met with the higher cost generation at Node 2. The difference in this case is that the load at Node 2 would fall as the price rose from $30 to

$1000. Load at node 2 would fall by 1% at $50 and 1$ for each subsequent $50/MW increase from $50 to $1000 for a total reduction in load at node 2 from 2000 MW to 1600MW, as shown in Figure 19. Given the rather inelastic demand that is assumed, it would be profitable for the monopolist at node 2 to raise the price to $1,000 despite the loss of sales.

Figure 19

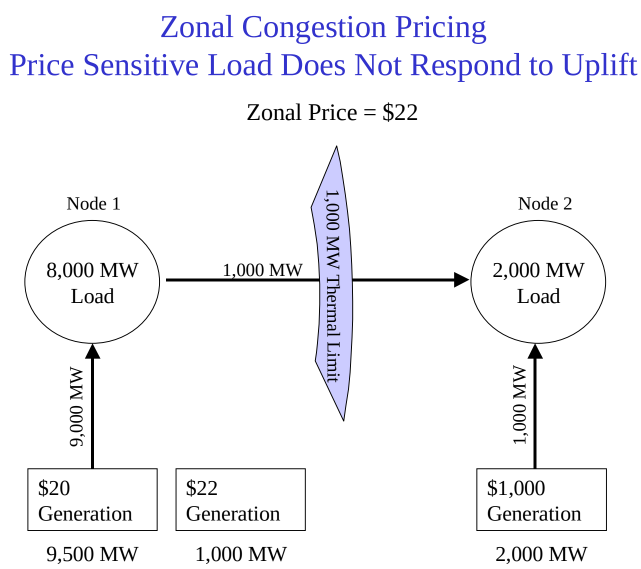


2. Zonal Congestion Pricing

In a pricing system based on least-cost dispatch and zonal congestion pricing for a zone including node 1 and node 2, competitive generators at node 1 would again find it profitable to bid their capacity into the market at $20. The generator with market power at node 2, on the other hand, would offer its capacity into the market at $1000. Based on these bids, the least cost unconstrained dispatch as shown in Figure 18 would be to dispatch the low cost generation at node 1 to meet the entire load in the zone and the zonal price would be $22. This generation schedule, however, would violate the transmission limit between nodes 1 and 2, requiring use of the system operator's zonal congestion management scheme.

Because it would be necessary to back down 500 MW of generators at node 1 with running costs of $20, the system operator would sell power to the constrained off generators at $20 (i.e. it would make constrained off payments of up to $2 *1000 MW) in a competitive generation market at node 1. In addition, the system operator would need to constrain on generation at node 2, and would therefore need to buy power from the assumed monopolist at Node 2 at a price of $1000/MW. If price sensitive load responded to the zonal price only (i.e. did not take uplift into account in its consumption decisions) then there would be no price response from the load and the resulting dispatch would be as shown in Figure 20.

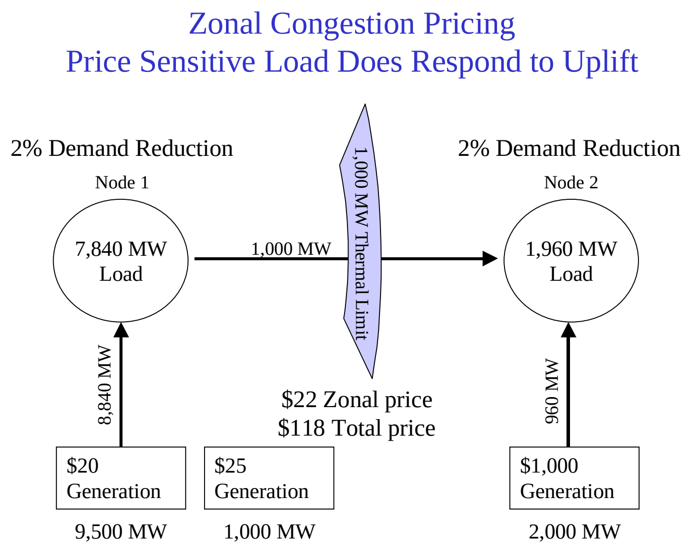
Figure 20



If it were instead assumed that uplift was assigned on an hour by hour basis to loads and anticipated in consumption decisions, then the total cost of $118/MW would cause load to reduce consumption by 2% throughout the zone, resulting in the dispatch shown in Figure 21[31]. It is noteworthy that zonal congestion pricing causes load to reduce consumption throughout the zone, although only the reduction in consumption at node 2 serves to reduce purchases of high cost power.

31 The total cost to load would include the zonal price $22/MW, $.20 in constrained off payments ($2*860/9,800 = .196, and $95.8 in constrained on payments ($978 * 960/9,800 = 95.8).

Figure 21



3. Comparison

It can be seen that nodal pricing reduces the profitability of the exercise of market power, relative to zonal congestion pricing, if demand is price sensitive. In the example above, however, the equilibrium price paid to the monopoly generator at node 2 would be $1000 under either zonal congestion pricing or nodal (or inter-zonal) pricing and the existence of price elastic demand has little impact on the profitability for this generator of exercising market power. However, if the market power at node 2 did not arise from the existence of a single monopoly generator but instead from a dominant firm with a capacity of 1200MW facing a competitive fringe controlling the remaining 800 MW of capacity, then nodal and zonal congestion pricing systems would result in different outcomes. Under zonal congestion pricing, the profits of the dominant firm would be maximized by withholding output and raising the price at node 2 to $1000, as shown in Table 22. Although there would be some reduction in sales from raising prices, it would be profitable for the dominant firm at Node 2 to raise its offer price to the price cap because the zonal price averaging would limit the impact of this increase on the zonal sales price and the sales of the dominant firm.

Table 22

Zonal Congestion Pricing with Cost Sensitive Load
Dominant Firm at Node 2

Market Demand	Load Price	Node 2 Demand	Dominant Firm at Node 2 Price	Output	Margin	Profits
MW	$/MW	MW	$/MW	MW	$/MW	$
10,000	23	2,000	30	200	0	0
10,000	49	2,000	290	200	260	52,000
9,900	99	1,980	797.8571	180	797.8571	138,214.3
9,800	118	1,960	1,000	160	970	155,200

Under nodal pricing, this dominant firm would still find it profitable to exercise market power but would find it unprofitable to raise prices above $199/MWh because of the loss of sales as it raised prices, see Table 23. Because all of the price increase would fall on customers within the constrained region, the resulting loss in sales would deter the dominant firm from further price increases. It is particularly in this environment of price sensitive load that nodal pricing can lead to more competitive outcomes than would prevail under zonal congestion pricing.

Table 23

Nodal Pricing with Price Sensitive Load
Dominant Firm at Node 2

Market Demand	Node 2 Price	Node 2 Demand	Dominant Firm at Node 2 Price	Output	Margin	Profits
MW	$/MW	MW	$/MW	MW	$/MW	$
10,000	30	2,000	30	200	0	0
10,000	49	2,000	49	200	19	3,800
9,980	99	1,980	99	180	69	12,420
9,960	149	1,960	149	160	119	19,040
9,940	199	1,940	199	140	169	23,660
9,920	249	1,920	249	120	219	26,280
9,900	299	1,900	299	100	269	26,900
9,880	349	1,880	349	80	319	25,520
9,860	399	1,860	399	60	369	22,140
9,840	449	1,840	449	40	419	16,760

It cannot, however, be shown that nodal pricing would always lead to a market equilibrium in terms of price and output that is superior to zonal pricing if the demand curve is downward sloping and generators within a transmission constrained region possess market power.[32] For a further discussion, see the appendix.

VII. Network Model

The preceding examples have assumed a simple radial system with one line connecting two buses in which there is no parallel flow. If that simplistic assumption is relaxed, the potential for zonal congestion pricing to create or exacerbate market power becomes much more pronounced. The example is modified by assuming that there are 9500 MW of $20/MW generation located at Node A, along with 8000 MW of load. There is also 2000 MW of load located at node C, along with 2000MW of $30 generation. Finally, there is 2000 MW of $26 generation located at node B (see Figure 24).[31.2]

[32] A counter example would have the property that there is an extremely elastic region of the demand curve at such a low price that the firm with locational market power would find it most profitable to raise its bid to the bid cap under nodal pricing, accepting a large loss in sales, while the ability of such a firm to earn very large margins under zonal congestion pricing without commensurately raising the total cost of power to load in the constrained region (because the firms high margin is in effect extracted from customers located outside the constrained region) would cause the firm to raise its offer price sufficiently to raise the zonal price just up to the highly elastic point on the zonal demand curve.

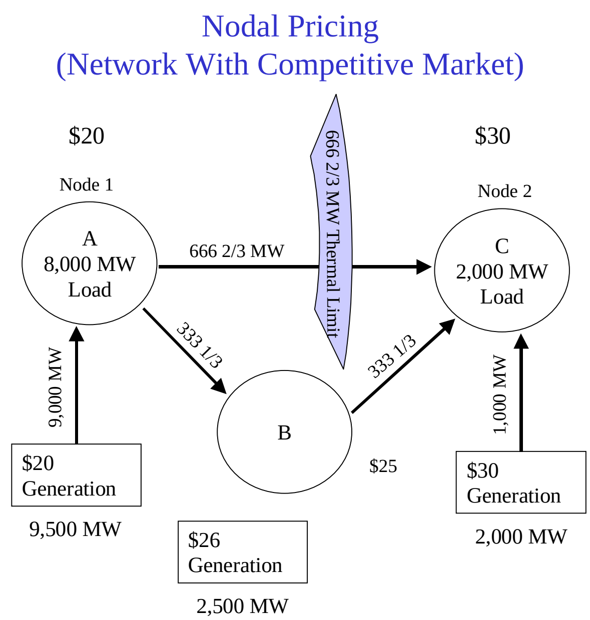
[31.2] For simplicity, each of the lines in Figure 24 has equal reactance and zero resistance.

A. Competition

1. Nodal Congestion Pricing

In a market based on least-cost dispatch and nodal congestion pricing, competitive generators at nodes A, B, and C would find it profitable to offer their output into the market at their costs. Based on these bids, the least-cost dispatch would be to employ the low cost generation at Node A to meet the load at nodes A and C until the transmission constraint between nodes A and C became binding. The least cost redispatch to meet the remaining load at Node C would be to dispatch the $30 generation at node C. The market price of power would be $20 at Node A, $30 at Node C and $25 at Node B[33]. Because the price at B would be less than the running costs of the generation located there, none of the generation at node B would be dispatched.

Figure 24



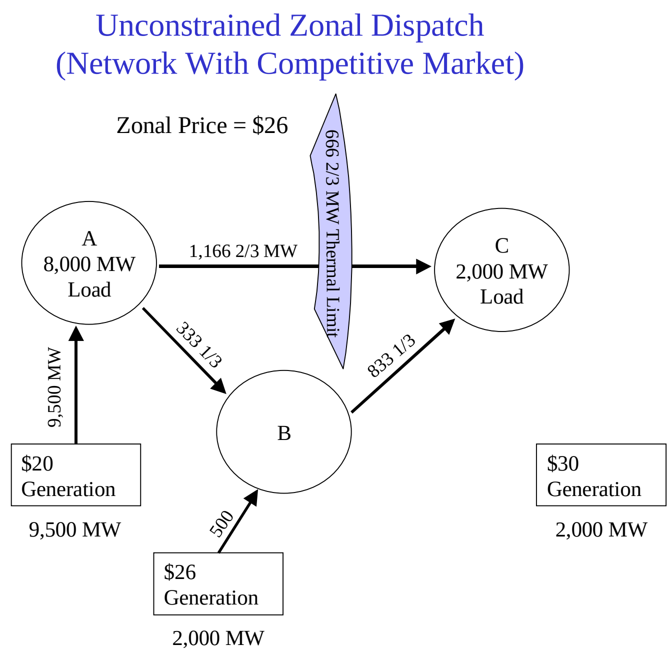
2. Zonal Congestion Pricing

In a pricing system based on least-cost dispatch and zonal congestion pricing for a single zone that included nodes A, B and C, competitive generators at node A, B and C would find it profitable to offer their output into the market at their incremental cost. Based on

[33] The market price of energy is $25 at node B because an incremental MW of load at B would be met at least cost, given the transmission constraint, by generating ½ MW at A and ½ MW at B. Meeting load at B solely with generation at A would over load line A-C.

these bids, the least-cost dispatch would be to dispatch all of the low cost generation at node A to meet the load in the zone and then to meet the remaining load with 500MW of $26 generation at Node B. The zonal price would therefore be $26 as shown in Figure 25.

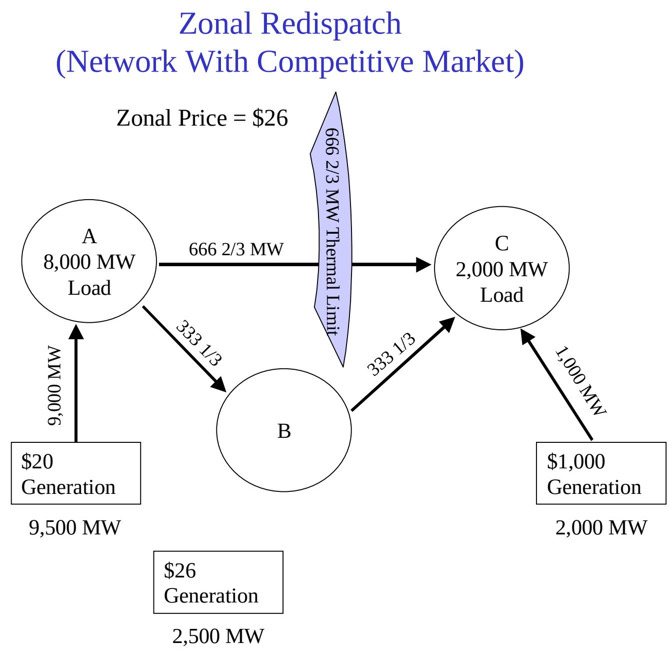
Figure 25



This generation schedule, however, would violate the transmission limit between nodes A and C (as also shown in Figure 25 the flows on line A-C would be 1166 2/3MW vs. a limit of 666 2/3MW), requiring use of the system operator's zonal congestion management scheme. Because the zonal price would be $26 compared to the $20 running cost of generators located at node A, the marginal generators located at node A would require constrained off payments of $6/MW to reduce generation. Because it would be necessary to back down 500 MW of generators with incremental generating cost of $20 (as well as 500MW of generators located at Node B with incremental running costs of $26), in a competitive generation market the system operator would make constrained off payments of $6 *1000 MW.[34] In addition, the system operator would need to constrain on 1000MW of $30 generation at node 2, paying $4 * 1,000 MW in constrained on payments. The resulting dispatch would be as shown Figure 26.

[34] In California terms, the system operator would sell power to the constrained off generators at $20 enabling them to cover the obligations to deliver for which they were paid $26.

Figure 26



Zonal congestion pricing would again raise the cost of meeting load by $6/MW because of the inflation of the zonal price in the unconstrained dispatch, see Table 27.

Table 27

Cost To Load
Network With Competitive Market

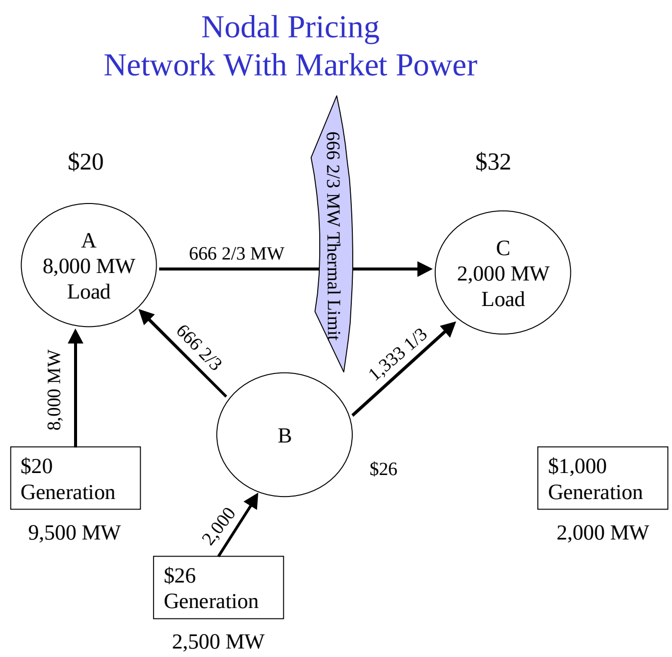
	Nodal Pricing		**Zonal Pricing**	
	Price	**Payments**	**Price**	**Payments**
Node A	$20	$160,000	$26	$208,000
Node C	$30	$60,000	$26	$52,000
Congestion Rent Credits		$10,000		0
Constrained On/Off Payments		0		$10,000
Net Payments		$210,000		$270,000

B. Unmitigated Market power

1. Nodal Congestion Pricing

We now consider the case in which all of the generation at Node C is commonly owned and raises its bid price to $1000/MW. Strikingly, it is seen in Figure 28 that under nodal pricing, the price at Node C rises only to $32 and none of the generation at Node C is dispatched. In fact, therefore, the prices charged by a monopoly generation owner at Node C would be capped by the threat of competition from generation located at node B, even when the constraint on the line A-C was binding. The reason for this outcome is that the dispatch of the higher cost generation at Node B while reducing generation at Node A, reduces flows on the line A-C allowing additional power to be delivered to Node C.

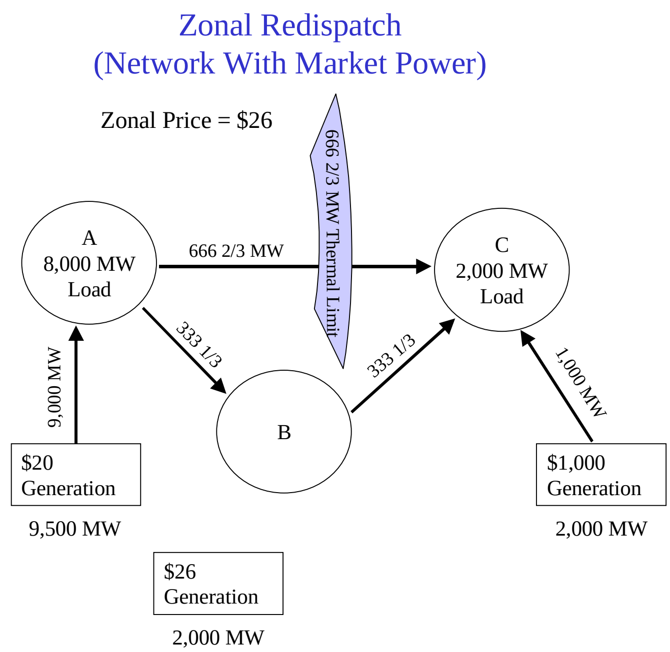
Figure 28



2. Zonal Congestion Pricing

Under zonal congestion pricing, however, the same increase in the bid price of generation at Node C would be profitable, because the least cost redispatch would be based on the zonal price, treating generation at nodes A and B the same, as shown in Figure 29. If generation at nodes A and B are treated the same, the lower cost generation at A would be dispatched in favor of generation at B (as the $6/MW constrained off payment would be more attractive to generators at B). If the zonal congestion pricing were somehow modified to treat generation at Nodes A and B differently and dispatch higher priced generation at node B in place of lower price generation at A, then the zonal congestion pricing would have become nodal pricing (or inter-zonal pricing if nodes A and B were split into separate zones) and the nodal and zonal equilibrium would be the same.

Figure 29



In this example, therefore zonal congestion pricing facilitates the exercise of locational market power and raises the cost of power to load as seen in Table 30.

Table 30

Cost To Load
Network With Market Power

	Nodal Pricing		Zonal Pricing	
	Price	**Payments**	**Price**	**Payments**
Node A	$20	$160,000	$26	$208,000
Node C	$32	$64,000	$26	$52,000
Total		$224,000		$260,000
Congestion Rent Credits		$12,000		0
Constrained On/Off Payments		0		$980,000
Net Payments		$212,000		$1,240,000

VIII. Conclusions

Local market power presents a complication for the analysis of policy in electricity markets. The issue is complex and dependent on the context of particular facts. However, in the choice between market pricing models based on nodal pricing that recognizes different prices at every location, and zonal pricing that creates administrative aggregations to reallocate costs, there is a nearly dominant answer. The result may appear counterintuitive, but nodal pricing is preferred for efficiency reasons and to mitigate market power. Confusion on this principle may arise from a failure to distinguish between the beneficial effects of real expansion of the transmission grid to allow competition over a larger region, and the detrimental effects of cost averaging and reallocation through the administrative creation of large zones in the face of real transmission congestion. In the latter case, zonal aggregation subsidizes the monopolist and increases the profits that can be extracted through the exercise of market power. By contrast, nodal pricing supports the market and expands the range of tools available to help mitigate market power.

APPENDIX
AGGREGATION AND LOCAL MARKET POWER

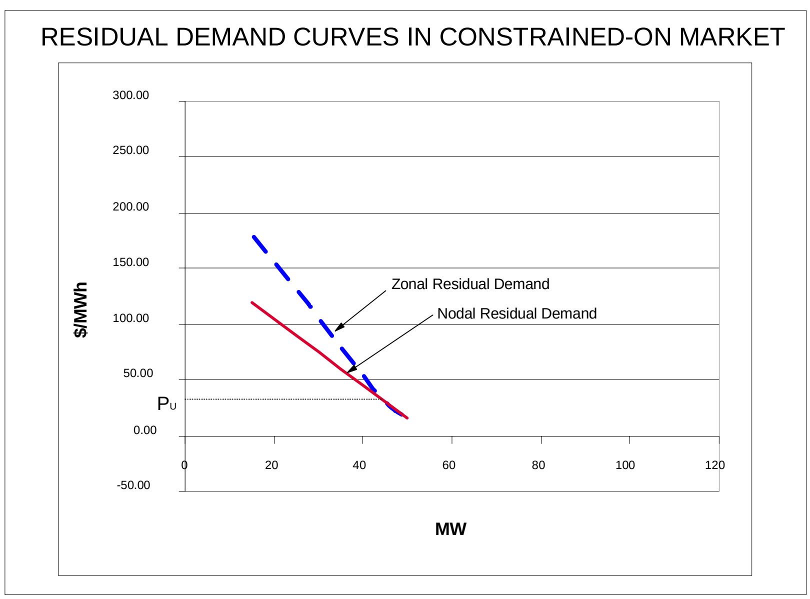
Consider a problem in zonal aggregation in the face of transmission constraints. Ignore the effects of loop flow but allow for a transmission limit on a radial connection between two locations. The two market models are nodal and zonal. We consider representative pricing rules for each approach and consider the difference in the market results for the market participants and for a generator exercising market power at one of the locations.

When the transmission constraint binds under the nodal model, there are two different prices. At the constrained-off end of the line, the price is lower. At the constrained-on end, the price is higher.

We are interested in the effect on prices in the constrained-on region when there is local market power. Suppose that the constrained-on region has a generator with market power. All other participants, both the supply and demand, are price takers. Then the generator with market power will face the familiar condition of a monopolist with a residual demand curve. The monopolist will maximize its profits by producing at the point where its marginal revenue equals its marginal cost. Let the nodal market solution be denoted as the price and quantity (p_N,q_N). With total variable costs of TC, the monopolist's profit is

$$\pi_N = p_N q_N - TC\left(q_N\right).$$

The alternative approach would be to treat the two locations as a single zone. For this single zone, there is a hypothetical unconstrained price p_U. However, when constrained by the transmission limit, a market balance at this price is not feasible. There must be some reduction of generation in the constrained-off region and some increase in generation in the constrained-on region. We will focus on the interaction within the constrained-on region where there is local market power.



Under the zonal model in the constrained-on region, we must pay the price bid by the generator with market power. The difference between this price and the unconstrained price is allocated across both locations in an average uplift. The actual allocation of uplift charges would depend on the details and the level of final load in the two locations. However, for simplicity, we suppose that the share of the uplift allocated to the constrained-on region price is well approximated over the relevant range by a constant α. Then the price (p) seen by the other market participants would be related to the price charged by the local monopolist (p_Z) according to the relationship:

$$p = p_U + \alpha(p_Z - p_U).$$

From the perspective of the monopolist, therefore, there is a new residual demand curve at its location. As shown in the figure, this zonal residual demand curve is related to the original nodal residual demand curve for the corresponding prices. At the unconstrained price the two curves intersect. Above the unconstrained price, the zonal demand curve is less elastic because only part of the higher price is actually applied in the local market.

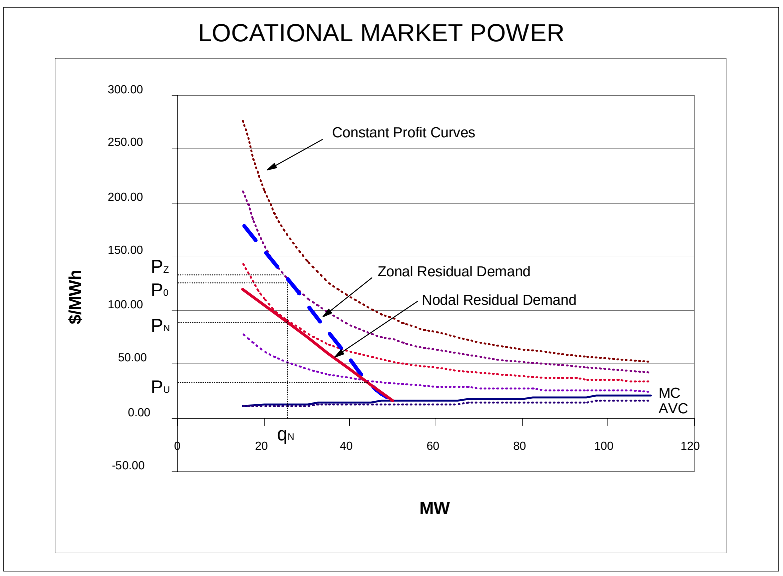
The exact shape of this new zonal residual demand curve is not immediately important for the first observation. The demand curve is necessarily to the right of the nodal residual demand curve. It is apparent, therefore, that the profits of the monopolist must be at least as large under the zonal solution as under the nodal market. In particular, let (p_Z,q_Z) be the zonal solution with profit as

$$\pi_Z = p_Z q_Z - TC(q_Z).$$

Then we have

$$\pi_N \le \pi_Z.$$

In all the interesting cases we would expect this inequality to be strict, with the zonal treatment amounting to a subsidy for the generator exercising market power.



If we take the nodal solution as the benchmark case, we can ask further about what happens to prices and quantities. Is the price paid to the monopolist also higher under the zonal model? Is the quantity provided by the monopolist lower?

Consider optimal solutions in each market. The figure shows the profit maximizing solution for the monopolist in each case. The monopolist is not required to meet demand, so production is inside or on the residual demand curve. There is no administrative price cap. Here we focus on the interesting case where the profit maximizing solution is at a point where a constant profit curve is just tangent to the relevant residual demand curve.

Let price p_0 be the price on the zonal inverse demand curve at the nodal quantity solution, or $p_0=p_Z(q_N)$. Hence, we see that this price is inversely related to the fraction α of the constrained-on payments assigned to the local participants. As long as $\alpha<1$ and there is some demand elasticity, we have $p_0>p_N$. Hence,

$$\pi_N < \pi_0 = p_0 q_N - TC\left(q_N\right) \leq \pi_Z .$$

Clearly the profit must be higher by at least the amount of the implicit price subsidy.

To address the impact on the prices and quantities, we impose some regularity conditions on the problem. First, assume that the average variable cost curve (AVC(q)=TC(q)/q) is convex. Then the profit isoquants must also be convex. The profit isoquants are increasing outward over the relevant range. Further, assume that the nodal residual demand curve is concave above the unconstrained price. This would imply that the zonal residual demand curve is also concave over this range. For simplicity, assume the demand and cost curves are differentiable, and the demand curves are invertible.[35] Under these conditions, we have enough convexity to assure us that a local optimum is a global optimum, and we need only examine the local behavior.

In the case of the price being higher or lower, we can see that at the price p_N, the slopes of the profit isoquants are decreasing as q increases. Similarly, by concavity, at each price the slope of the zonal residual demand curve is everywhere steeper than that of the nodal residual demand curve. The profit isoquant that goes through the point (p_N,q_N) is tangent to the demand curve at that point. Hence, the profit isoquant at the point $(p_N,q_Z(p_N))$ must intersect the demand curve such that the profit isoquant is below to the left and above to the right. It follows that the new optimal solution at p_Z, the price paid to the monopolist, must be at a point that is higher, or:

$$p_N < p_Z .$$

The condition on the shape of the average cost curve is not very restrictive. Although the concavity of the residual demand curves is more restrictive, it is consistent with all examples using linear demand and supply.[36] Furthermore, these conditions are clearly not necessary conditions to produce the increase in prices. As shown in the figure, all that is

[35] The invertible demand curve restriction excludes perfectly flat demand curves. This could always be approximated by an invertible demand curve, and would have the impact only of changing some of the strict inequalities to weak inequalities.

[36] Strictly speaking, here we require concavity only between p_U and p_N. Outcomes below the unconstrained price are ruled out by the optimality of p_N. Outcomes at higher prices only reinforce the result.

required is that the profit isoquant at the point *$(p_N,q_Z(p_N))$* must intersect the demand curve such that the profit isoquant is below to the left and above to the right. This would be true whenever the residual demand curve is not too convex, as can be seen in the figure.

The higher price may not imply a lower quantity. It may be that the subsidy to the monopolist is sufficient to induce some increase in production to attract more of the higher margins that the subsidy creates. However, there are circumstances under which this would not be true, and there would be both a higher price and a lower output. Here we continue the convexity assumptions and look to the local behavior at the point (p_0,q_N).

For the zonal model we have the residual demand curve:

$$q_Z\left(p_Z\right)=q_N\left(p_U+\alpha\left(p_Z-p_U\right)\right).$$

Hence, for the inverse demand curve, we have

$$\frac{dp_Z}{dq}=\frac{1}{\alpha}\frac{dp_N}{dq}.$$

At the quantity q_N, we can evaluate the slopes of the demand curve and the profit isoquants. Let p_π be the iso-profit line. Then,

$$p_{\pi_N}=\frac{\pi_N}{q}+AVC\left(q\right).$$

We have from the optimality condition at the point (p_N,q_N) that

$$\frac{dp_N}{dq}=\frac{dp_{\pi_N}}{dq}=-\frac{\pi_N}{q_N^2}+\frac{dAVC(q_N)}{dq}.$$

As above, the profit at the point (p_0,q_N) where the zonal residual demand curve has the same quantity is

$$\pi_0=p_0q_N-TC\left(q_N\right).$$

Therefore, we have the corresponding profit isoquant as:

$$p_{\pi_0}=\frac{\pi_0}{q}+AVC\left(q\right).$$

From this we have the derivative at the intersection point as:

$$\frac{dp_{\pi_0}}{dq} = -\frac{\pi_0}{q_N^2} + \frac{dAVC(q_N)}{dq}.$$

We are interested in the comparison of the derivatives of the zonal inverse demand curve and the profit isoquant. In particular, a zonal price for the monopolist higher than p_0 and an optimal quantity q_Z lower than q_N would be implied by a positive sign for the quantity

$$\frac{dp_{\pi_0}}{dq} - \frac{dp_Z}{dq}.$$

With this condition, the profit isoquant would again intersect the demand curve at (p_0,q_N) such that the profit isoquant is below to the left and above to the right. Then it would follow that the new optimal solution at p_Z must be at a point that is higher, or:

$$\begin{aligned} &p_0 < p_Z, \\ &and \\ &q_Z < q_N. \end{aligned}$$

The sign can be evaluated as:

$$\frac{dp_{\pi_0}}{dq} - \frac{dp_Z}{dq} = -\frac{\pi_0}{q_N^2} + \frac{dAVC(q_N)}{dq} - \frac{1}{\alpha}\left[-\frac{\pi_N}{q_N^2} + \frac{dAVC(q_N)}{dq}\right].$$

Recall that

$$\begin{aligned} &p_N = p_U + \alpha\left(p_0 - p_U\right). \\ &Hence, \\ &p_0 = \frac{p_N - (1-\alpha)\,p_U}{\alpha}, \\ &and \\ &\pi_0 = \frac{p_N - (1-\alpha)\,p_U}{\alpha} q_N - TC\left(q_N\right). \end{aligned}$$

Therefore,

$$\begin{aligned} \frac{dp_{\pi_0}}{dq} - \frac{dp_Z}{dq} = -\frac{\frac{p_N - (1-\alpha)\,p_U}{\alpha} q_N - TC\left(q_N\right)}{q_N^2} + \frac{dAVC(q_N)}{dq} \\ -\frac{1}{\alpha}\left[-\frac{p_N q_N - TC\left(q_N\right)}{q_N^2} + \frac{dAVC(q_N)}{dq}\right]. \end{aligned}$$

or,

$$\frac{dp_{\pi_0}}{dq} - \frac{dp_Z}{dq} = \left[\frac{1-\alpha}{\alpha}\right]\left[\frac{p_U}{q_N} - \frac{TC\left(q_N\right)}{q_N^2} - \frac{dAVC(q_N)}{dq}\right].$$

Now,

$$\frac{dAVC(q_N)}{dq} = -\frac{TC(q_N)}{q_N^2} + \frac{MC(q_N)}{q_N}.$$

Therefore,

$$\frac{dp_{\pi_0}}{dq} - \frac{dp_Z}{dq} = \left[\frac{1-\alpha}{\alpha}\right]\left[\frac{p_U}{q_N} - \frac{TC(q_N)}{q_N^2} + \frac{TC(q_N)}{q_N^2} - \frac{MC(q_N)}{q_N}\right]$$
$$= \left[\frac{1-\alpha}{\alpha q_N}\right]\left[p_U - MC(q_N)\right].$$

Apparently, the sign is determined by the difference between the unconstrained price and the marginal cost at the nodal solution quantity. With equality, the optimality conditions would be satisfied and $p_0 = p_Z$. Combining the previous results under the concavity conditions, if the unconstrained price is less than the marginal cost, we have:

$$p_U < MC(q_N) \quad \Rightarrow \quad p_N < p_Z < p_0, \quad q_N < q_Z \quad and \quad \pi_N < \pi_0 < \pi_Z.$$

If the unconstrained price is greater than the marginal cost, we have:

$$p_U > MC(q_N) \quad \Rightarrow \quad p_N < p_0 < p_Z, \quad q_Z < q_N \quad and \quad \pi_N < \pi_0 < \pi_Z.$$

It would seem that either possibility could occur. It would not be unusual for the monopoly generator to have a low marginal cost and be able to compete in the unconstrained market. It does not compete because of its dominance, not because of its high cost. In this case, the effect of the subsidy would be to increase the monopolist's price and profit, lower its output, and increase the customer price in both locations above the nodal prices.

If the monopolist were a high cost generator, it could still exercise its market power. Now the effect of the subsidy would be to raise its price and profit and raise the customer price in the constrained-of region, but increase its production and lower the price in the constrained-on region.

Other cases may apply. It might be possible to construct and example with a sufficiently convex demand curve such that the nodal residual demand curve has an optimal solution at a high price and the zonal residual demand curve has an optimal solution at a lower price. Here the monopolist's marginal costs would have to be low, and the monopolist would reap higher profit by increasing output substantially in response to the subsidy. Although the market demand curve is likely to be inelastic, this case of highly elastic residual demand facing the monopolist might be connected to a highly elastic and high cost supply of a competitive fringe. Furthermore, this competitive fringe would have to be on the demand side of the meter, as other high cost suppliers in the market are paid only their bid, not the bid plus the uplift. This would be possible in principle, although it would seem an unlikely combination that there would be both a large and highly elastic competitive supply on the customer side of the meter, high enough load to induce transmission constraints, and local market power.

The impact on the monopolist is clearer than the full efficiency effects in the market. The monopolist is paid its price p_Z and receives a subsidy and a higher profit under the zonal model compared to the nodal model. The cost of the subsidy is borne in part by those in the other region that are treated as part of the same zone. The direction of the efficiency effects in the constrained-off zone is a deadweight loss. This must be balanced in the constrained-on zone with the effect on production. In the concave residual demand case, with the unconstrained price above marginal costs, there is lower production and a further deadweight loss, for an unambiguous loss in efficiency. However, if the residual demand curve is sufficiently convex or the monopolist has a relatively high cost generator, production could increase and the deadweight loss due to the exercise of market power in the constrained-on region would be reduced, leading to an ambiguous overall impact on static efficiency. Of course, there would be a large transfer from customers to the monopolist.

With the larger wealth transfers of the zonal approach and the discrepancy between the prices paid and charged at the margin, the zonal model would give price signals that would reduce dynamic efficiency and create a need for other interventions in the market to compensate for the subsidy effects.

The extension of the analysis to networks with market power extending across many locations presents further complications. However, it would be surprising if the qualitative result for the simple radial model--that zonal pricing subsidizes the monopolist--would change.