Appendix A – Discussion of Nodal versus Zonal Pricing and Locational Marginal Pricing versus other Pricing Mechanisms

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Discussions over pricing mechanisms for energy markets have often raised two important decisions in market design. The first is whether implementation should use nodal or zonal pricing, and the second is whether it should use locational marginal pricing or pay-as-bid pricing. This appendix gives a brief overview of the lessons learned from other market implementations and studies.

A1. Nodal versus Zonal Pricing

Wholesale electricity markets differ from most markets for two important reasons; 1) electricity is the same no matter where or how it is produced, and 2) once electricity is produced it flows to an unknown point based on the state of the transmission system and the laws of physics. In a networked system these characteristics make it impossible to determine the specific source from which electricity is generated. Consequently, pricing electricity is inherently difficult to do.

In a large, networked transmission system there are numerous points of injection and withdrawal. The changing state of the transmission network can limit the amount of energy that can be injected or withdrawn at various points and times (transmission congestion). Therefore, a variety of mechanisms have been used to capture these effects and model the pricing of electricity at the wholesale market level.

A1.1 Pricing Variations and Zonal Pricing

If a transmission network has sufficient capacity to limit or eliminate the incidence of transmission congestion, then generating units in a geographic market region can easily sell their energy at any point within that region. However, there are nearly always constraints on transmission system operation and/or costs associated with moving energy across systems (hurdle rates) that lead to local variations or segments in the market for electricity.

When electricity utilities first organized into regional markets, many of them chose to create one or more aggregated zones for pricing purposes (zonal market). These aggregations were made largely to minimize the complexity of the pricing settlement mechanisms. New England (ISO-NE) and the PJM each initially organized with one zone, and New York (NYISO), Texas (ERCOT), and California (CAISO) each began operation with multiple zones.

In a zonal market, the market price is determined by the clearing price of the last megawatt generated to meet load at any point in the geographic zone. When localized congestion occurs within a zone it increases prices for all parties within the zone, even if they are not located near the congestion and even if they are not contributing to the congestion in any way. This results in overall higher system costs because everyone in the zone is paying the higher congestion costs whereas with nodal pricing, only the parties at the congested location would be paying the increased cost.

Because pricing zones by their very nature do not represent the effects of localized transmission constraints, the calculated dispatch of generation for a zone often needs to be adjusted to create a physically possible dispatch configuration for actual operation. This re-dispatching increases costs.

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Various transmission congestion mechanisms have been created over time to mitigate these pre-schedule inefficiencies and change the actual dispatch of generation to more feasible physical configurations. Not surprisingly, market participants have often able to determine when their units were likely to benefit from these intra-zonal congestion mechanisms, leading to the submission of schedules and prices that could take financial advantage of those facts. This increased market costs and required ever more complex congestion adjustment mechanisms to deal with the problems.

A1.2 Transitioning to Nodal Pricing

Over time, market designers found that the congestion mechanisms that were created to minimize operating inefficiencies associated with zonal pricing ended up becoming more complicated than the modeling of fully nodal pricing itself,[20] leading to the adoption of nodal pricing mechanisms for generation.

Nodal pricing is a method in which market prices are calculated for a number of locations on the transmission network (nodes) that represent physical locations on the system. These locations can include both generators and loads. The price at each node represents the incremental cost of serving one additional megawatt of load at that location subject to system constraints. Using this method it is easier to determine which parties are responsible for transmission congestion and charge them accordingly.

Currently, all organized markets in the United States that used zonal pricing have transitioned to nodal pricing for generation. However, most markets still use zonal pricing for loads, although the PJM employs nodal pricing for loads and the CAISO has been ordered by FERC to disaggregate their three main load zones.

The experience of markets that have transitioned from zonal to nodal generation pricing can be summarized in these points:

- Zones are found to not be good approximations of actual transmission congestion
- Zonal pricing structures require an increasing amount of market costs be devoted to congestion management mechanisms to make final dispatch schedules physically feasible
- Zonal congestion management mechanisms grow more complex and costly as participants alter their scheduling and bidding behavior to benefit from adjustments
- Analysis of nodal pricing for generation within organized markets is evaluated to determine the net benefits and costs
- Nodal pricing for generation is adopted

A1.3 ERCOT's Experience with Transitioning from Zonal to Nodal Pricing

ERCOT used a zonal pricing model until November 2010. In November 2004, a cost-benefit analysis for a nodal market was performed for ERCOT[21] that identified a net-present value of approximately $7.3 billion in consumer savings over the first 10 years of operation, attributable to the nodal market re-design.

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[20] Baldick, et al. (2011)

[21] ERCOT (2004)

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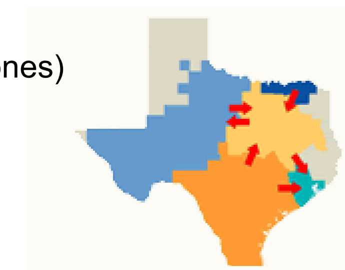
Despite the identification of savings, the implementation of a nodal market in ERCOT experienced a number of delays during which time a number of new generating units and transmission upgrades were added to the system. In 2008, an update of the 2004 analysis was performed. The scope of the updated analysis was somewhat narrowed but it still identified approximately $5.6 billion in consumer savings over the first ten years of operation. Additionally, updates of other benefits associated with the nodal market were found to likely be even greater than those in the 2004 report. For example: benefits associated with the enhanced ability to rapidly respond to higher penetration of variable generation resources were identified as having increased.

ERCOT has identified the following simplified comparison to show the benefits associated with its transition to nodal pricing.[22]

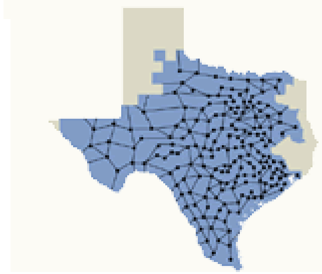
ERCOT Zonal Market (five Congestion Management Zones)

- Insufficient price transparency
- Resources grouped by portfolio
- Indirect assignment of local congestion



ERCOT Nodal Market (>4000 Nodes)

- Improved price signals
- Improved dispatch efficiencies
- Direct assignment of local congestion



A1.3 CAISO's Estimated Benefits from Nodal Pricing

The CAISO transitioned from its original zonal market design to nodal pricing, along with several other market changes, as part of its Market Redesign and Technology Upgrade (MRTU) in April 2009. Because there were numerous changes made as part of the MRTU it is difficult to assess the impact of the change to nodal pricing alone. However, one report[23] estimated that the benefits of the introduction of nodal pricing into the CAISO translated into approximately $105 million in annual cost reductions.

A1.4 Why Nodal Pricing was Chosen

Within the United States, most organized wholesale electricity markets have made the transition from zonal to nodal pricing, and empirical analyses to date support using nodal pricing for generation as the most efficient market mechanism to manage localized congestion. Therefore, it is appropriate that the proposed EIM use this level of granularity in its Market Design.

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[22] *Understanding Texas Nodal Implementation*

[23] Wolack (2011)

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A2. Locational Marginal Pricing versus Pay-as-Bid Pricing

The proposed EIM is a sub-hourly, real-time energy market providing centralized, automated, region-wide generation dispatch.

The pricing mechanism for the EIM conceptual design is Location Marginal Pricing (LMP), also known as “uniform pricing.” This appendix describes the LMP, compares it to pay-as-bid pricing, and explains why the LMP is considered to be the superior mechanism for the EIM.

A2.1 How the LMP Works

The LMP is an economic dispatch concept wherein energy and transmission congestion prices are calculated in specific areas based on the marginal cost to generate power to serve those areas. The goal of the LMP is to achieve optimal (least cost) generator dispatch by minimizing locational energy and congestion prices.

As indicated in its name, there are two components that are considered in the LMP: *Locational* and *Marginal*. *Locational* refers to the fact that prices for energy may be different in different locations. These differences arise from transmission congestion constraints and the characteristics of generating units in the dispatch stack. *Marginal* refers to the price to produce the next megawatt-hour of energy after load has been served in a given location (energy produced on the margin).

A2.1.1 Market Clearing Price

Under LMP auctions, all selected generators will be paid the same price, regardless of their original offer prices. This price is referred to as the market clearing price or the uniform price. The market clearing price for each node and each time period is set as the offered price of energy from the most expensive generator chosen to meet load (the marginal price).

If there are no transmission constraints and line losses are negligible in the market grid area, the LMP will be virtually the same across the entire market area. With transmission constraints, variations in the LMP will exist between different nodes.

Under LMP auctions, generators have an incentive to offer energy at or very close to their marginal cost of generation. This marginal cost is essentially the same as the variable costs of generation.[24] If generators bid higher than that cost, the likelihood of being selected for dispatch is reduced and they may miss out on an opportunity to supply power. If generators bid below that cost, they will not receive enough revenue to cover the variable costs of generation, so they would be better-off not to participate in the market at all. Thus, when generators offer energy at or near the marginal cost of generation, they maximize the chance of being selected while ensuring that they will not operate unprofitably if they are selected. This principle has been called the “no regrets rule”[25] in LMP designs. The generators have an incentive to offer energy at the lowest possible price they are willing to sell it and, if they are selected, they will receive a price that is guaranteed to be no lower (and most likely higher) than that price.

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[24] Alternatively, generators may have an incentive to offer energy at their opportunity cost, which represents the price level at which they could sell their power outside the market. There would be no reason to bid into the market at a lower price than they could get elsewhere.

[25] Ott, Andrew (2007)

Generators also have an incentive to minimize their operating costs to maximize revenue. Generators whose operating costs are at or near the market clearing price will net little income above variable costs to apply towards fixed costs. Alternatively, generators with lower operating costs will net more income to pay down long-term obligations and record profits.

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A2.1.2 Other Markets That Use the LMP

Most of the electric markets in North America use some form of the LMP in calculating energy prices. These include the following:

- PJM
- New York ISO
- New England ISO
- California ISO
- SPP
- ERCOT
- MISO
- IESO (Ontario)
- AESO (Alberta)

A2.2 Pay-As-Bid Pricing

An alternative method for setting energy prices is known as pay-as-bid. Under pay-as-bid auctions, winning suppliers are paid the same price as their actual bids and not the market clearing price. These are also referred to as “discriminatory auctions” because the selected generators all receive different prices based on their respective offers.

Proponents for this method have reasoned that it would be less costly to pay generators their bid price than the higher market clearing prices. While it may sound reasonable not to pay a generator more than the offered price, it is important to note that generators change their bidding strategy under the pay-as-bid auctions—the offered price under pay-as-bid will not be the same price under uniform pricing. In fact, studies of behavior under simulated electricity auction markets show that prices would be higher in pay-as-bid auctions.[26] Changing the auction format does not change the underlying economic and physical realities of the market.

Instead of offering a price close to the marginal cost of generation (typical for LMP auctions), a generator under a pay-as-bid mechanism has a strong incentive to estimate what the market clearing price will be and make an offer close to that price to maximize revenues. Generators would need to balance their probability of being selected (by offering a price just below the price of the last bidder that will meet customer demand) against decreased profits from bidding too low, and thus leaving money on the table.

This concept is illustrated in Figure A-1, taken from the report *Uniform-Pricing versus Pay-as-Bid in Wholesale Electricity Markets: Does it Make a Difference?*[27]

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[26] Rassenti et al. (2003), Mount et al. (2001) and Abbink et al. (2003).

[27] Tierney et al. (2008)

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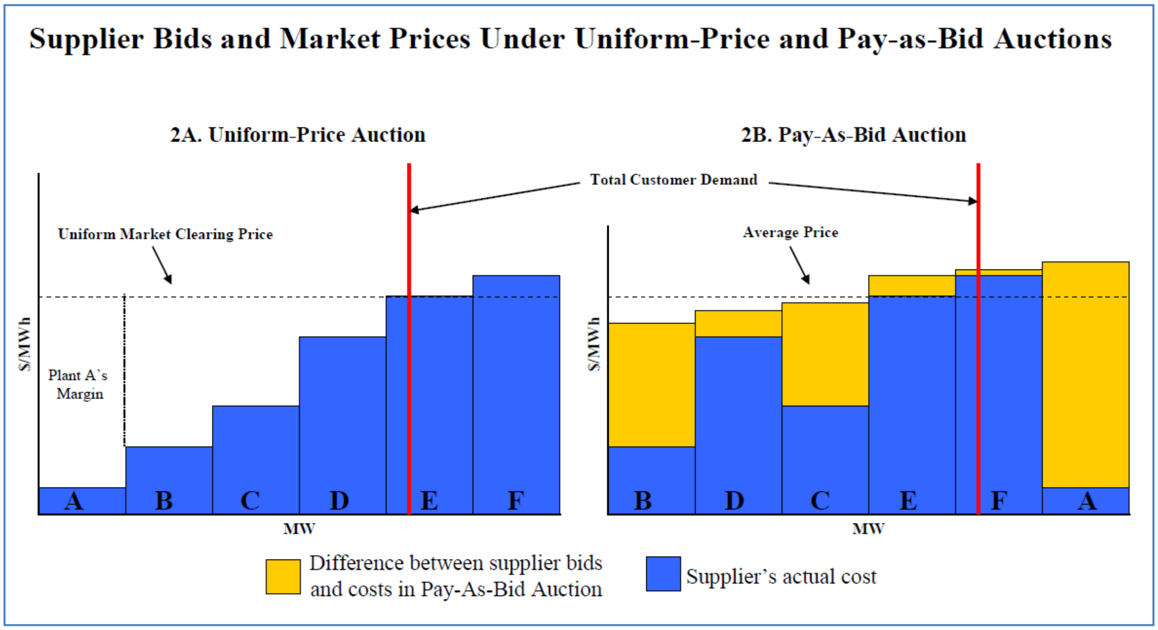

Figure A-1 (Source: Susan Tierney and Todd Schatizki, *Uniform-Pricing versus Pay-as-Bid in Wholesale Electricity Markets: Does it Make a Difference?*)

In Figure A-1, the chart on the left illustrates a typical scenario under uniform-price auctions. The generator supply offers are ranked from lowest to highest. The low-cost offers are selected until enough generation has been selected to meet the forecast demand. The last selected unit sets the market clearing price under that dispatch stack. The difference between the generators' offered price and the market clearing price represents the generators' respective profit margin.

In Figure A-1, the chart on the right illustrates a hypothetical scenario under pay-as-bid auctions. Instead of offering energy at the marginal cost of generation, each supplier offers a price close to what they anticipate the market clearing price will be. The increased price above their marginal costs of production is illustrated by the yellow bars. As one would expect, the offered prices for each plant are significantly different under these two scenarios. While energy offers under the pay-as-bid scenario are higher than under the uniform-pricing, it is difficult to quantify how that changes the total cost of generation for the system.

The behavior of guessing at market clearing prices in pay-as-bid schemes may result in additional randomness to supplier offers as electricity market forces constantly change. The true low-cost plants may not be selected for the dispatch stack, resulting in a sub-optimal use of resources for the system.

A2.3 Why the LMP Was Chosen

The question of which pricing mechanism is better has been raised by many and there is significant literature on this topic.[28] However, the LMP has been shown to be the most efficient pricing mechanism. While some pay-as-bid schemes have been attempted, all North American markets have moved to a clearing price method based on the LMP.

[28] For example, Tierney et al. (2008) and Kahn et al. (2001)

There are several reasons why LMP market designs are superior to pay-as-bid market designs. Some are listed below:

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- The LMP is more likely to result in a dispatch stack that truly reflects the market supply curve and grid conditions. Conversely, pay-as-bid auctions may not result in a least-cost dispatch stack and are more likely to result in an inefficient plant dispatch.
- For generators, it is less complicated to select the energy price they should offer under LMP auctions. Conversely, pay-as-bid pricing likely leads to more opportunities to game the system.
- Because pay-as-bid auctions put greater emphasis on market price forecasting, all generators would face increased costs to ramp up energy price forecasting programs. These costs would ultimately find their way down to the rate payers.
- Because pay-as-bid auctions put greater emphasis on market price forecasting, smaller suppliers are put at a disadvantage. The costs associated with operating a robust energy price forecasting program would be proportionately more burdensome on suppliers with small generator fleets. Larger generators will be able to afford higher quality forecasts to maintain a competitive advantage in the market.
- The LMP provides accurate price signals to market participants for generation and demand-side resources.
- Studies show that market prices are higher overall in the pay-as-bid markets compared to uniform pricing markets.