

The current LMP study will use historical shadow prices from the constrained algorithm to provide some insight into what locational prices might look like in Ontario. It is important to remember that the results will be limited in their value as the current shadow prices are not used for settlement in Ontario, and as such, have very little, if any impact on participant behaviour. We are confident that at least some participants would adjust their behaviour if exposed to these prices rather than an unconstrained Ontario price. The IESO will be providing a qualitative analysis of the impacts of participant behaviour adjustments.

The study will use data beginning in the summer of 2004 after the introduction of MIO to the constrained algorithm. The IESO will provide monthly average prices as well as on-peak and off-peak average prices for several different types of locational price models described below. The raw data for the study will also be available (off line via CD) to any participants who request it.

### **Locational Pricing – Possible Models**

The study will examine several possible locational price schemes starting with the highest level of granularity, nodal pricing, and moving to less precise definitions of location, or zones. It is possible to split Ontario into larger or smaller zones. Typically zones are created based upon an electrical model of the province, focusing on the major electrical interfaces as the dividing points between zones. Ideally, all nodes within a zone will experience similar nodal prices.

Depending on the frequency of congestion on the major interfaces, it is also possible that multiple electrical zones may experience similar prices the majority of the time. If this is the case, these smaller zones could be combined into a larger zone. For the purposes of this study, the IESO will examine several zonal pricing models, including one zone, two zones, ten zones and some smaller number of zones based on the similarity of prices from the ten zone model.

It should be noted that it is possible to produce mixed locational prices; for example, the use of nodal prices for dispatchable participants, and zonal pricing for non-dispatchable participants. These decisions do not impact the parameters for the current study.

The following text describes some of the characteristics of different locational pricing methodologies and models in more detail.

#### *Nodal Methodology*

Nodal pricing can be considered the “truest” form of locational marginal pricing, where prices are calculated for each node – consumer withdrawal or generation injection point –

on the power system. Each consumer pays the price at their node and each generator is paid the price at their node. This is the most efficient methodology possible as participants get the most accurate price signal for their location and there is no need for constraint payments<sup>1</sup> or uplift charge for line losses. In this case, dispatchable facilities are only dispatched when they are “in the money” i.e. the nodal price is above the offer price from generators or below the bid price for consumers. This methodology is however complex, especially for consumers who may only be infrequently interested in their nodal prices such as at times when they are evaluating their forward contracting options. For such participants, the simplification brought about by zonal prices or even trading reference bus pricing may be preferred. The nodal methodology also raises concerns about local market power during times of congestion, and about the liquidity of available trading opportunities at any particular nodal location.

### *Zonal Methodology*

The region is divided into zones, usually based on electrical system characteristics such that there is little transmission congestion within a zone. The zone boundaries could also be determined by grouping nodes with similar prices, which should create the same result, as the nodal prices only materially vary when transmission congestion is present. Settlement prices are calculated<sup>2</sup> for each zone and all consumers within that zone pay that same price and all generators within that zone are paid that price. The use of zones may require some form of side payment for dispatchable facilities that are “constrained” such that they are dispatched when not “in the money” i.e. zonal price is below offer for generators or above bid for consumers. The quantity of side payments will depend on how close the zone price is to the nodal prices within it – better price convergence means smaller side payments – and this is determined by the level of congestion and to a lesser extent by the losses within the zone. However, because it is not possible to completely eliminate intra-zonal congestion – especially that caused by contingencies on the transmission system – there will likely be a need for some form of side payment scheme. This methodology could be much simpler to implement from an IT systems perspective when compared with the full nodal methodology although this would depend on the number of zones.

### *Combination of Zonal and Nodal Methodologies*

It is possible to combine these two concepts in a locational pricing methodology and several other electricity markets currently do this. The most commonly used combination is to use nodal for generators and zonal for consumers. This allows the efficiency gains of the nodal methodology for generation, which are the only dispatchable facilities in most other jurisdictions. On the consumption and therefore non-dispatchable side, the simpler zonal methodology is used. The amount of efficiency loss caused by using zonal for non-dispatchable participants is dependent on the zone boundaries – a zonal

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<sup>1</sup> There may still be occasions when ISO operators are required to dispatch facilities out of merit for reliability reasons and some form of compensation would likely be needed for this. This is handled via a production cost guarantee in several other jurisdictions.

<sup>2</sup> There are different ways to calculate the zone prices. One would be to use an average of the nodal prices within the zone. Another method is to use an unconstrained model of the zone to calculate price as we currently do for the market clearing price in Ontario (a one-zone model).

methodology where there is very little price difference between the nodes within a zone is more efficient. In Ontario, the question of how to treat dispatchable load would have to be addressed in a zonal/nodal combination methodology – will they be charged the nodal price, paralleling the fact that generation is paid the nodal price, or would they be charged the zonal price, as would be all other consumers in the zone. Similarly, the treatment of non-dispatchable generation would also have to be addressed.

#### *Discussion of Possible Models for Ontario*

Several possible zonal models exist for Ontario, depending on the criteria used to determine the zone boundaries. As mentioned earlier, a ten-zone model of the province has existed for many years based on significant transmission interfaces. However, the historical nodal price data indicates that several of these zones have very similar average prices, which might suggest that a simpler model with fewer zones will do. Depending on how liberally one applies similar price criteria for zone definition, this could result in as few as two zones – one for the North or Northwest and another for the remainder of the province - or even one single zone for all of Ontario. These different zonal models could employ a true zonal methodology in which the zonal price applies to all market participants or could be combined with a nodal methodology such that all dispatchable facilities within a zone are settled based on their nodal prices and all non-dispatchable facilities are settled based on the zonal price. However, if a zonal methodology is applied to dispatchable facilities, then some type of constraint payment scheme will likely be required. This is especially true if the one-zone model is used, as one can expect constraint payment levels similar to that of our current uniform pricing model. The historical data analysis presented here does not provide estimates of the constraint payments that would be required if dispatchable facilities are settled based on zonal prices, but the need for such payments can be roughly estimated by examining the degree of variability of the nodal prices in the zone at any particular time.

## Appendix A

### Possible Hedging Mechanisms:

Under a uniform pricing scheme, market participants are not directly exposed to the pricing risks associated with transmission congestion. Congestion costs are passed on to consumers through an uplift charge that cannot be hedged. A transition to a location-based pricing scheme can result in congestion risk for Participants, as the cost of congestion is included in the locational price. This creates a need for some kind of hedging mechanism to manage this risk. Markets that have implemented locational pricing have addressed this need through Financial Transmission Rights (FTR's). Similar to the IESO's intertie Financial Transmission Rights, internal FTR's allow Participants to hedge the risks associated with internal transmission congestion.

In markets using location-based pricing, the cost of congestion is represented by the difference in price between nodes or zones. The cost of congestion is not directly charged to any participant, but is reflected when the market operator pays producers less than it charges consumers. This results in a surplus, referred to as congestion rent. Holders of transmission rights are entitled to a share of this congestion rent.

In designing a system of financial transmission rights, some fundamental questions have to be addressed. The type of FTR's available, the method of allocation, and revenue adequacy are all important considerations.

#### *Types of FTR*

A financial transmission right is directional in nature. FTR's are defined by a source (point of injection), a sink (point of withdrawal), and a MW quantity. There are two types of FTR commonly used in markets employing location-based pricing: obligation rights and option rights. An obligation right entitles its holder to receive a share of congestion rents when congestion is positive, but also imposes an obligation to pay congestion costs when congestion is negative. An option right entitles its holder to receive positive congestion revenues, but carries no obligation to pay negative congestion revenues. Within the IESO-administered markets, option rights are available to manage price risks associated with intertie trading.

#### *Method of Allocation*

There are two basic approaches to the allocation of FTR's: direct allocation, and allocation through an auction. Direct allocation has been used in other jurisdictions to grant rights to Load-Serving Entities (LSE's) with pre-existing transmission arrangements. In a variation of this approach, some markets grant Auction Revenue Rights (ARR's), which entitle holders to a share of revenues from the FTR auction.

FTR's can also be allocated through a competitive bidding process. FTR auctions are conducted as a single locational clearing price auction, where Participants can bid for FTR's between any two locations (nodes or zones). This approach is used in the IESO-

administered TR market for intertie zones. Revenues raised in IESO TR auctions are used to help fund payments to Transmission Rights holders.

### *Revenue Adequacy*

A fundamental requirement of any FTR market is that it must be self-funding. To ensure that sufficient revenues are raised, ISO's require that all FTR's pass a "simultaneous feasibility test." The implied flow associated with awarded FTR's must be physically feasible, with FTR limits approximating transmission system limits for the time period covered by the FTR. As long as the capability of the transmission system does not change, the physically feasible solution should ensure that enough congestion rent is collected to honour the FTR's. To further reduce the risk of a funding shortfall, a combination of long-term and short-term FTR's are generally awarded. Long term rights are awarded based on the expected minimum capabilities of the transmission system for the time covered by FTR. This leaves some capacity available for short term FTR's, which can be assessed and awarded closer to the dispatch day. Despite efforts to ensure revenue adequacy, situations may arise that result in shortfalls. Transmission outages, changes in generator availability, and unexpected loop flows can result in system limits that differ from the assumptions underlying the FTR's. Administrative procedures are required to address these situations. Generally, ISO's set aside surplus funds to cover any potential shortfalls. If surplus funds are insufficient to cover shortfalls, FTR's can either be paid out fully, with costs passed on to participants through an uplift, or paid partially on a pro rata basis.

### *Transitional Measures*

Any transition to a location-based pricing model will result in Market Participants being exposed to congestion-related price risks for the first time. To mitigate the potential impacts, and allow Participants to become familiar with a new market structure, transitional measures may be appropriate. It may be necessary to "grandfather" rights to certain participants through direct allocation of transmission rights or auction revenue rights. Other markets have experimented with grandfathered rights for LSE's. Such an arrangement could be phased out over a period of time, as affected participants gain knowledge of the market. The Ontario market, without LSE's, would need to discuss how such grandfathered rights should be allocated.

### *Other Features*

The rules governing transmission rights can be tailored to fit the locational pricing model chosen. For the most part, other jurisdictions allow point to point FTR's within LMP markets. If a zonal pricing model was implemented, zone to zone FTR's would be appropriate. Markets that use a different pricing regime for producers and consumers (i.e. nodal/zonal) have experimented with zone to zone FTR's that can be "unbundled" into point to point components. This approach ensures consistency and contributes to liquidity in the TR market.

For an overview of the IESO's existing Transmission Rights Market:

<http://www.ieso.ca/imoweb/marketplaceTraining/TransmissionIntro.asp>