The Importance of Marginal Loss Pricing in an RTO Environment

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Abstract

This paper shows the importance of pricing transmission losses in a way that reflects the real costs of moving power. Real power losses are a major component of transmission service and should be priced accurately, especially in systems that cover wide geographical areas. With the formation of large Regional Transmission Organizations (RTO) and the move toward elimination of pancaked transmission rates, transmission prices need to reflect the increase in transmission losses as power moves across large geographical distances. In order for generators and consumers to receive correct short-term and long-term signals with regard to transmission, the loss component should be accurately priced using marginal cost methods. Especially for systems with large fluctuations in power flows, and hence losses, it is necessary to implement a locational real-time pricing mechanism of real-power losses.

Introduction

Power transmission across long distances occurs with regular frequency around the country. As Regional Transmission Organizations (RTOs) form and start to eliminate pancaked transmission rates, accurate pricing of transmission losses becomes especially important. Losses on transmission lines increase with distance and can become significant when generators are located far from the load being served.

In this paper, we first discuss how different pricing methods for transmission losses work and how they affect economic efficiency. Many Independent System Operators (ISOs) in North America have adopted average pricing methods for losses, at least for interim periods. Given that many ISO's are using market-based methods for pricing of energy, capacity and ancillary services to encourage efficient dispatch and investment decisions, ignoring accurate pricing for transmission losses may result in a significant distortion of the true cost of transmission.[1] This may in turn result in transmission and generation investment decisions that are less than optimal.

We demonstrate the importance of accurate pricing of transmission losses by examining recent marginal loss data from the New York ISO (NYISO). We find significant loss factors associated with moving power from one end of the state to the other. We also present simulation results showing potentially significant marginal loss factors for other control areas, including Pennsylvania- New Jersey-Maryland (PJM), the Independent System Operator of New England (ISO New England), and the Western Systems Coordinating Council (WSCC). As a result of marginal loss pricing, generators placed closer to their load experience an advantage over farther generators which must transmit their power over greater distances to reach load served. The incorporation of a more accurate pricing for losses results in a more efficient dispatch.

Pricing Methods

Transmission losses along a line are always proportional to the square of the power flow along the line (see sidebar on *Calculating Transmission Losses*). However, the actual losses at each bus in the system change from moment to moment, depending on the flows of power within the entire system. In general, ISO's in the U.S. and Canada price transmission losses according to one of three methods:[2]

System Average Pricing. With this pricing method, everyone is charged the average cost of losses for the entire system. This method takes the total cost of system losses divided by system load and does not discriminate between generators or load based on their locations or their contribution to system losses.

Marginal Cost Pricing. With marginal cost pricing, transmission losses are priced according to marginal loss factors. The marginal loss factor at a bus is the percentage increase in system losses caused by a small increase in power injection or withdrawal at the bus. As shown below, marginal loss factors are always twice average loss factors, so this pricing method will result in an over-collection of loss revenues.

From an economic efficiency standpoint, marginal cost pricing for losses will result in the most efficient dispatch, since each generator will see a price for losses that exactly reflects the incremental cost of transmission arising from their contribution to power flows. This result is consistent with pricing in a competitive market, where the market price is equal to the marginal cost of the last supplier needed to meet demand.

Scaled Marginal Cost Pricing. This method is similar to marginal cost pricing except that the price for losses is scaled downwards so that over-collection of revenues does not occur. The California ISO, for example, uses a proportional scale factor which is applied to generators. However, doing so results in prices that distort incentives to produce the most efficient dispatch. Stott [3] presents a method for scaling marginal loss factors by a constant shift factor, which preserves the correct incentives for generators without over-collection.

Calculating Transmission Losses

For transmission losses, the marginal losses are always twice the average losses because line losses are proportional to the square of the power flow, Q along the line:

Losses = aQ^2

where a is a constant. Average losses are total losses divided by total flow, or:

$$\text{Average loss factor} = \frac{\text{Total losses}}{\text{Total flows}} = \frac{aQ^2}{Q} = aQ$$

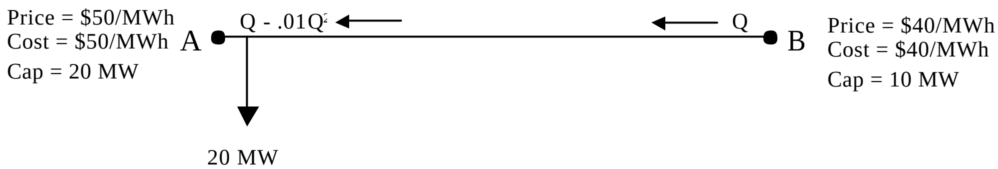
The marginal losses are the incremental change in line losses due to a change in power flow and are calculated as follows:

$$\frac{\partial}{\partial Q}(Losses) = \frac{\partial}{\partial Q}(aQ^2) = 2aQ$$

Charging for marginal losses will always result in an over-collection of revenues, as the revenues will be double the costs. As an illustrative example, consider a simple two-bus system with nodal and marginal loss pricing, comprised of buses A and B, each with a generator attached.[4] Bus A has a generator costing \$50/MWh with a capacity of 20 MW and Bus B has a generator costing \$40/MWh with a capacity of 10 MW. Bus A also has a load of 20 MW. In this example, line losses are proportional to the square of the flow along the line (same as generation at Bus B), according to the formula:

Losses = $.01Q^2$

Therefore, if a quantity Q is injected at B, the quantity Q – .01Q^2 will be delivered at Bus A. See the figure below.



To solve for the optimal dispatch, we want to minimize total system cost. The total cost of generation is as follows:

TC = $40 x Q + $50 x [20 – (Q – .01Q^2)]

dTC/dQ = 40 – 50 + (50 x 2 x .01 x Q) = 0

Q = 10 MW

Thus, the solution which minimizes system cost (least-cost dispatch) is the one in which Generator B produces 10 MW, and 9 MW is delivered at Bus A; Generator A produces the remaining 11 MW, for a total of 20 MW delivered to load with 1 MW of losses.

The nodal prices can be calculated by choosing one of the buses as the reference bus and calculating prices at all other buses using the relationship:

$$P_i = (1 - L_i) P_E$$

where P_i is the price of energy at bus i, P_E is the price of energy at the reference bus, and L_i is the marginal loss factor for moving power from bus i to the reference bus. If we choose bus A to be the reference bus, we can calculate L_B very easily because we know the formula for losses when moving power from bus B to bus A. The marginal loss factor L_B can be calculated as follows:

$$\frac{\partial}{\partial Q}(Losses) = \frac{\partial}{\partial Q}(.01Q^2) = .02Q = .02 \times 10 = 20\%$$

Note that the marginal loss factor is twice the average loss factor, given:

$$\text{Average loss factor} = \frac{\text{Total losses}}{\text{Total flows}} = \frac{.01Q^2}{Q} = .01Q = 10\%$$

The price at the reference bus (bus A) is $50 because it is the marginal unit being dispatched. The price at bus B is therefore (1-0.2)*$50 = $40, and we know that the difference between the two must be the transmission charge for moving power from B to A. This transmission charge of $10/MWh is equal to the cost of losses in the absence of congestion.

Thus, Generator A is paid for producing 11 MW at $50/MWh, for a total of $550. Generator B is paid for producing 10 MW at $40/MWh for a total of $400. The total payment to generators is $950, only $900 of which would have been needed for energy absent losses (given 1 MW of losses). Load pays for 20 MW of energy at $50/MWh, for a total of $1000, $100 of which is a result of charging marginally for losses. In this case, the transmission owner collects $50 to pay for the losses and over-collects another $50. This over-collection is due to pricing losses at the margin, and since marginal losses are twice the average losses, we expect the over-collection to be equal to the cost of losses (1 MW at $50/MWh). The over-collection can be dealt with in two ways – either return the payments to consumers as a credit to an uplift charge (as is done in New York), or by scaling down marginal loss factors.

Case study: Transmission losses in New York

Although many systems in the U.S. do not price transmission losses on a marginal cost basis, the New York ISO (NY ISO) is one that does. Thus, we considered the New York ISO as a case study of a system, which provides nodal energy prices reflecting the actual marginal cost of losses in real time. We used historical real-time prices for zones in New York in 2000-2001 to calculate loss factors. We used this data to analyze the effect of losses on nodal energy prices and think about the implications for pricing policies.

First, we took data from the NY ISO website for real-time zonal prices from January 2000 to December 2001.[5] The data gave us the location-based marginal price of energy, the marginal cost of losses, and the marginal cost of congestion for each hour of the day, for the eleven zones in the NY ISO control area. We calculated loss factors as follows:

Loss factor (%) = Marginal cost of losses / Reference bus energy price

The reference bus energy price (E) was back-calculated from the location-based marginal price of energy using the following relation:

LBMP = E + L – C,

where: LBMP = Location-based marginal price
E = Reference bus energy price
L = Marginal cost of losses, and
C = Marginal cost of congestion.[6]

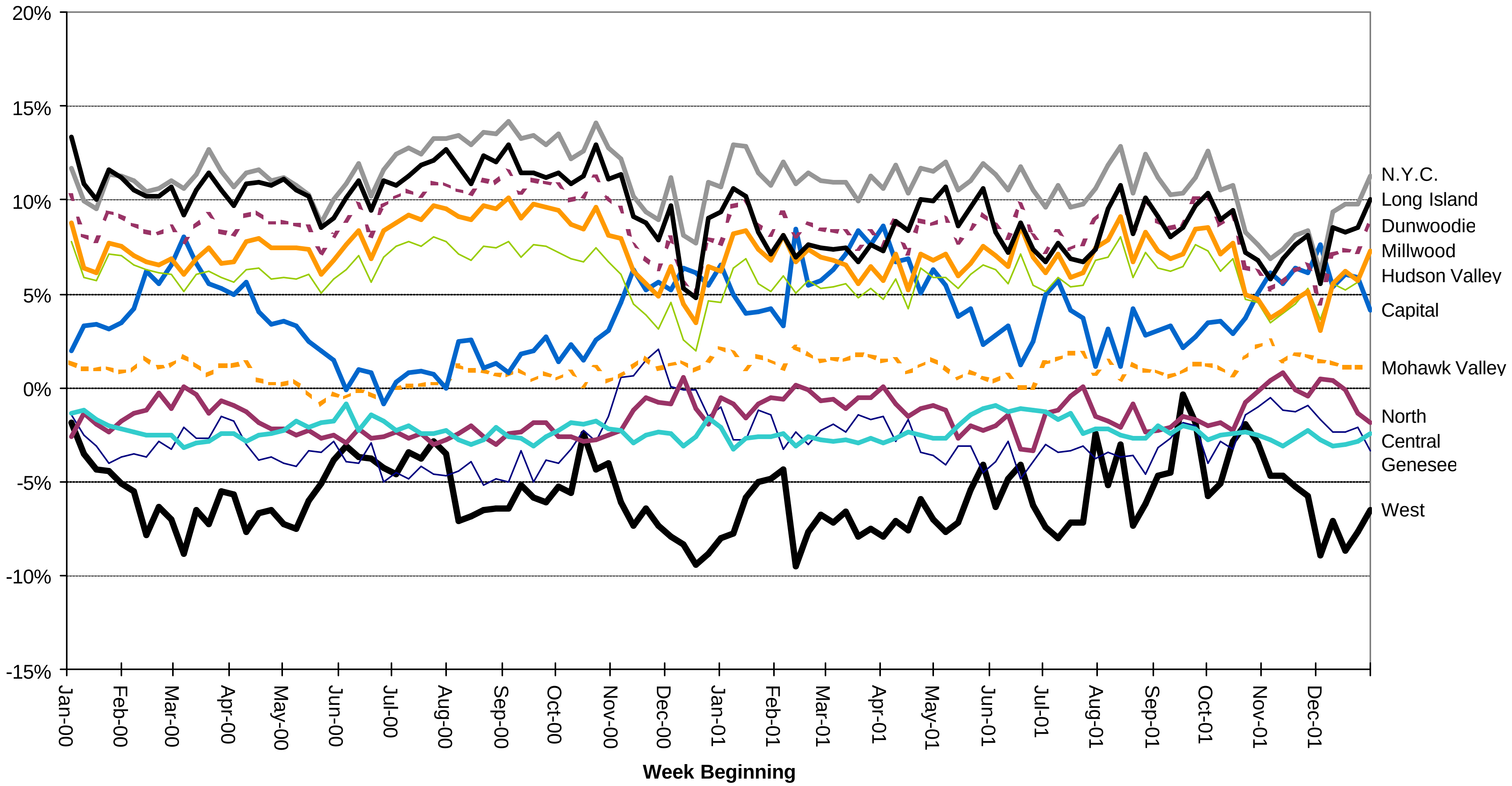
The marginal cost of losses (L) can be positive or negative, depending on the direction of flow away or toward the reference bus (located in Marcy, in central New York state). This means that points in western New York tend to have a negative loss factor and points near New York City tend to have a positive loss factor, since the flow of power is predominantly from western generators to eastern load centers. In other words, if we ignore the cost of congestion, prices in western New York would have a lower price than the reference bus price, and prices in eastern New York would have a higher price than the reference bus price. This price differential represents the cost of moving power from west to east. Loss factors are calculated with respect to the reference bus and can vary depending on the choice of the reference bus. However, the loss factor for moving power between any two buses at a given point in time will remain the same, and it can be calculated by taking the difference between the loss factors at the two buses. Thus, both price differential and the loss factor differential represent the cost of moving power from one bus to another.

We took the actual NY ISO data and plotted weekly average of marginal loss factors for New York's 11 zones, as seen Figure 1. From the data, we can see that loss factors in the New York City region average about 10-15%, and loss factors in the far western part of the state vary from –5% to –10%, so the total loss factor for moving power from the western part of the state to the NYC/Long Island area could be up to 20% or more.

On the whole, the data reflects what we might reasonably expect of transmission losses in New York. The variations in the loss factors show seasonal influences, since losses are dependent on the magnitude of the load. The regions in eastern New York exhibit similar fluctuation patterns, consistent with the eastern part of the state acting as a regional load center. Most importantly, the marginal loss factor differential demonstrates a significant cost in moving power from western generation sources to eastern load centers.

When loss factors are a significant component of the locational price, this will affect the order in which generators are dispatched. As an example, consider actual data from 6/19/2000 at 14:00 hours. In the west, a Huntley generator experienced a locational price of $20 including losses of –$1.50, i.e. the reference bus price was $21.50 and the loss factor for Huntley was –6.9%. A generator in New York City, Astoria, experienced a price of $25.28 including losses of $3.78 (a loss factor of 17.6%). Thus, if a generator at Huntley bid $20.00 and a generator in Astoria bid $25.28, even though the difference in bid prices appears large, both generators would be considered "equal" in the supply merit order. The reason is that the energy bid price would have to take into account the marginal cost of losses. In this example, it is possible that a generator with a "lower" bid price, such as a Huntley generator bidding $20.01, could actually be higher in the merit order than a generator with a "higher" bid, such as the Astoria generator bidding $25.28. The Astoria generator with the "higher" bid would be dispatched before the Huntley generator with the "lower" bid.

Fig. 1: Weekly Zonal Averages of Marginal Loss Factors in New York



Simulations: Loss Factors for PJM, New England, and WSCC

Since actual marginal loss data is not available from most ISO's, we ran simulations to evaluate the magnitude of the losses when moving power across a region. We used the PowerWorld® Simulator software, designed to simulate high voltage power system operation. The software solves a load flow case, given specific information about generation output, loads, and the transmission system. In calculating loss factors, the primary limitation of using the software is that the information represents one snapshot in time and one set of system conditions (typically we use a summer peak load case). The calculation is dependent on the accuracy and representative nature of the input file and to that extent may not reflect actual settings of phase-angle regulators, unplanned outages, etc. However, it can be used to ascertain the range of marginal losses factors for buses in a system.

We ran simulations for PJM, ISO New England, and WSCC, using load-flow cases from FERC 715 filings. For PJM and ISO New England we used a load-flow case for the year 2000, and for the WSCC we used a load-flow for 2004.

In PJM, the simulated results showed a wide range of marginal losses. Moving power from Homer City in western Pennsylvania to load centers in eastern New Jersey (such as Linden and Marion) incurs 15-19% losses. At the extreme, a transaction from Homer City to one end of the electrical system, e.g. on a low-voltage line to Bayview at the tip of the Delmarva peninsula, results in a 37% loss. Moving power between Indian River (in Delaware Bay) and load centers in eastern NJ incurs a 20-23% loss. By comparison, the system average loss factor for PJM was 3% for peak and 2.5% for off-peak in the year 2000.

In the simulation for ISO New England, flows from northern New England down to eastern Massachusetts (Medway area) show losses of over 10%, e.g. 11% from Champlain, VT, and 17% from Harris, ME. From the Medway area to southwestern Connecticut (e.g. Torrington) is an additional 10% loss and from Medway to Wellfleet is an additional 8% loss, so a power transfer from Maine to Wellfleet or from Maine to southwestern Connecticut would be over 25% loss.

In the WSCC area, loss factors showed over 30% losses (sometimes up to 40%) for moving power from Alberta (Edmonton) or from Colstrip, MT down to northern California (such as Pittsburg in the San Francisco Bay area). Moving power within the Northwest region could incur up to 20% losses, for example, between Colstrip and mid-Columbia.

Conclusions

From the data and analysis we find that it is very important to price transmission losses in a way that reflects the real costs of moving power. We found from actual data for the New York control area that the difference in loss factors could be up to 20%. Simulations for the northeastern and western regions of the U.S. showed differences in loss factors within an ISO control area ranging from 25-35%. Real power losses are a major component of transmission service and should be priced accurately, especially in systems that cover wide geographical areas like Ontario, the Midwest ISO, or the WSCC.

With the formation of large Regional Transmission Organizations (RTO) and the move toward elimination of pancaked transmission rates, transmission prices need to reflect the increase in transmission losses as power moves across large geographical distances. In order for generators and consumers to receive correct short-term and long-term signals with regard to transmission, the loss component should be accurately priced using marginal cost methods. Especially for systems with large fuctuations in power flows, and hence losses, it is necessary to implement a location real-time pricing mechanism of real-power losses.

Incorporating marginal loss pricing into real-time energy prices will lead to changes in generator bidding behavior. In general, generators located closer to their load will experience an advantage over those located farther from their load. In a control area where all losses are priced at the system average, a farther generator with a lower energy bid price will be dispatched before a closer generator with a higher bid price. However, in a marginal loss pricing scheme, that same generator with the lower energy price may find itself dispatched after a closer generator with a higher energy price, once the loss prices are factored in.

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[1] Fred C. Schweppe, Michael C. Caramanis, Richard D. Tabors, and Roger E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer, 1988).

[2] Laurence D. Kirsch, "Pricing the Grid: Comparing Transmission rates of the U.S. ISOs," *Public Utilities Fortnightly*, Feb. 15, 2000, at 30-42.

[3] Steven Stoft, "How to Charge Generators for Marginal Losses without Over-collecting," taken from *A Critique of the Phase II Tariff and a Proposal for Revisions,* evidence filed before the Alberta Energy and Utilities Board, July 30, 1999, http://www.stoft.com/x/other/albertaloss.pdf (April 1, 2002).

[4] Example taken from Stoft, 1999.

[5] This data was from the NY ISO OASIS, http://mis.nyiso.com/public/P-4Alist.htm (April 1, 2002).

[6] The NY ISO defines the marginal cost of congestion is defined as negative; therefore it is subtracted from the reference bus price to calculate the LBMP.