RTO West Losses Task Team

November 4, 2002

Losses

Purpose – Recommend a loss methodology to be used during the operations of RTO West. The RTO West Independent Board, will have the authority to change any methodology established at this time.

Time Frame – Recommendation for losses is required for the tariff drafting team about November 21.

Stage 2 Filing

The March 29,2002 filing said that losses would be handled, but did not specify the methodology. The filing did provide the following,

1. All schedules would be accepted
2. Schedules would be based on POR and POD (on RTO West transmission system)
3. Day ahead market based on bi-lateral agreements
4. Real time dispatch by RTO West operators
5. Self-provide and Self-tracking options
6. Settlement to follow

Definitions

Granularity options

1. System Losses – losses treated the same over the total control area.

2. Zonal Losses – losses treated the same over a geographically related set of buses defined by revenue quality metering and other requirements.

3. Nodal Losses – losses treated the same at a single bus or node.

4. SC Losses – losses treated the same on a SC bases.

Methodology options

1. Average Losses – Losses are allocated to all SC's within that granularity based on an established averaged over a period of time(hourly, on/off peak, daily, weekly, monthly, seasonally, yearly)

2. Zonal Losses – Losses are allocated to all SC's in a zone on a pro-rata base, internal losses are combined with imbalance energy for the zone by at the difference between net schedules and net interchange, external losses are based on flow into the zone, though losses or calculated based on flow and a loss factor for the zone.

3. Marginal Losses – Losses are allocated to SC's based on the calculated impact of the last MW at a bus on the system losses.

Working Assumptions agreed to at least once:

1. A share of RTOW TX losses be attributed (using loss factors yet to be determined) to each SC's balanced schedule, and settled for in the same way as the SCs' liability for Imbalance Energy;

2. The RTO West loss allocation method should strive to allocate losses in a manner that is consistent with the physical operation of the transmission system, so that losses allocated to SC's reflect the actual losses that they currently deal with.

3. Losses should be incorporated into the RTO's settlement process in a manner to allow both self-provision and purchase of losses.

Working Assumptions still with concerns:

1. A balanced schedule shall be deemed in Settlements to require an injection of (1+TLFI)*the nominally scheduled quantity, and a withdrawal of (1+TLFW)*Qscheduled. [Sorry about the lack of subscript]

2. The SC's liability for Losses shall be determined as the difference between the deemed injection/withdrawal quantity and that actually metered (for Settlements purposes) as injected/withdrawn at the relevant locations, and priced at the prevailing RT nodal price.

3. An equitable loss allocation methodology should allocate losses to both load and resources in a manner consistent with loss causation.

4. If a loss methodology is implemented that requires the RTO to directly acquire losses on a regular basis, the RTO should be encouraged to do so on a day ahead basis rather than relying on the real time market. Concern – Not the direction of Stage 2, this puts the RTO in the energy market, but this might be best for the RTO for some cases.

5. Stage 2 makes the PTO responsible for losses in all cases. Congestion rights of CTR or FTO or the lack of them does not change loss allocation. Converted or non-converted or pre-888 or any other contract provision with a PTO does not change the loss allocation. Some existing contracts have in kind return for losses, which Stage 2 turns over to the RTO, does not change loss allocation, but is a settlement issue. Use of a hub should not change loss allocation.

Best Practices

Losses Principle	CAISO(Marginal Scaled)	ERCOT(Average)	New York(Marginal)	Zonal	License Plate
accurate and based on reasonable identification of causation	• Adjusted to reflect actual losses • Locationally accurate (at least for resources, • Allocated only to resources	• Reasonably reflect actual losses • No locational component	• Highly accurate with the proper metering • Highly equitable	• Reflects actual losses	• Approx. accurate • Reflects each SC's due share of RTO West system losses
straightforward – easy to understand, simple to administer and reasonably predictable	• 3 sets of losses calculated every hour for every injection point isn't that simple. • Requires load flow to calculate • Easy to administer once calculated	• yes	• More complex than average losses • Loss rates vary with LMPs – not highly predictable	• Requires power flow results	• Simple to administer, easy to apply to schedules and trades • Stable TLFs, periodically adjusted (with due notice)
consistent for all system users	• Applied only to gen/imports	• Yes	• Yes	• Yes	• differentiates between existing (non-converted) users and new/ converted users
should not be "gameable."	• Isn't	• Isn't	• Isn't	• Isn't	• Can't be (or can be designed out).
consistent with market design	• Complicated, precise - consistent	• Does not factor in location	• Highly consistent with LMP and SMD	• Factors in some location (zones)	• fits with 'no cost shifts or shocks' principle • Has no effect on CM model
					•
Question					•
How are total amount of real losses considered	• Estimated through load flow. Discrepancies are included in UFE	• Seasonal estimates adjusted for actual load. Discrepancies included in UFE	• At any given moment, generation is balanced against load.	Estimated through load flow.	• Actual losses metered. Difference (+/-) from allocated losses

					goes to RTOW Error A/c
How are losses valued	Self-supplied or as imbalance energy	Self-supplied by QSE or as imbalance energy	• Based on differences in LMP.	Self-supplied or as imbalance energy	• Any not self-supplied priced at RT
How are costs allocated	To generators/imports	To QSE's based on load served	• Everyone pays the marginal rate.	By line flows	• via SC's liability for Imbalance Energy • via SC's contract/ tariff terms
What happens to difference between scheduled and actual losses	GMMs calculated based on actual load, any discrepancy uplifted	Deemed loss factor based on actual load used for settlement, discrepancies uplifted	• Over collection is credited to loads as a discount to uplift charges.	• Settlement	• Sched-Allocated to SC's IE • Allocated-Actual to RTOW Loss Error A/c
When are losses determined	• Estimated week ahead and day ahead • Actual determined ex post	• Estimated day ahead • Actual determined ex post	• As frequently as LMPs are calculated.	• Estimated day ahead • Actual determined ex post	• Estimated at Adequacy test, and at DA • Actual via Settlement meter
Will method accommodate returns in kind or concurrent provision?	• Losses are settled each hour based on that hour's market price if not self-provided. • No later returns	• Losses are settled each interval based on that interval's demand if not self-provided	• No	• In settlement	• Yes to both • SC is liable concurrently
Is there an adjustment for current load and/or weather	• All losses settled based on actual system conditions	• Adjusted to expected actual losses on system wide basis.	• Calculated for the conditions existing at any specific moment in time.	• Based on actual losses	• If need identified
Major advantages	• Accurate locational price signal • Real time loss allocation • Easy to allocate	• Easy to understand and administer • Real time allocation	• Provides a clear price signal to customers of the current cost of energy. • Assesses each user of the transmission	• Uses existing metering • Zones are close to existing allocation • Allocates through losses	• Simple to apply and administer • Transparent and predictable • TLFs stable, adjusted only

			system according to actual use of the facilities at the time they are being used.		periodically • Honors existing contracts and rights • Allows SCs to self-supply or buy @ RT prices
Major Disadvantages	• Lots of numbers • Multiple estimated iterations • Assumes all load has same loss responsibility. • Difficult to duplicate	• No locational component for generation or load	• Over collects revenue necessary to purchase energy needed to supply total system losses. • Requires proper metering, which could be quite expensive.	• Requires power flow estimated losses	• Not locational • Doesn't recover actual losses concurrently • Needs monitored Loss Error A/c, with agreed limits

Details on the different proposals are attached.

CAISO	Attachment 1
RECOT	Attachment 2
NYISO	Attachment 3
Zonal	Attachment 4
License Plate	Attachment 5

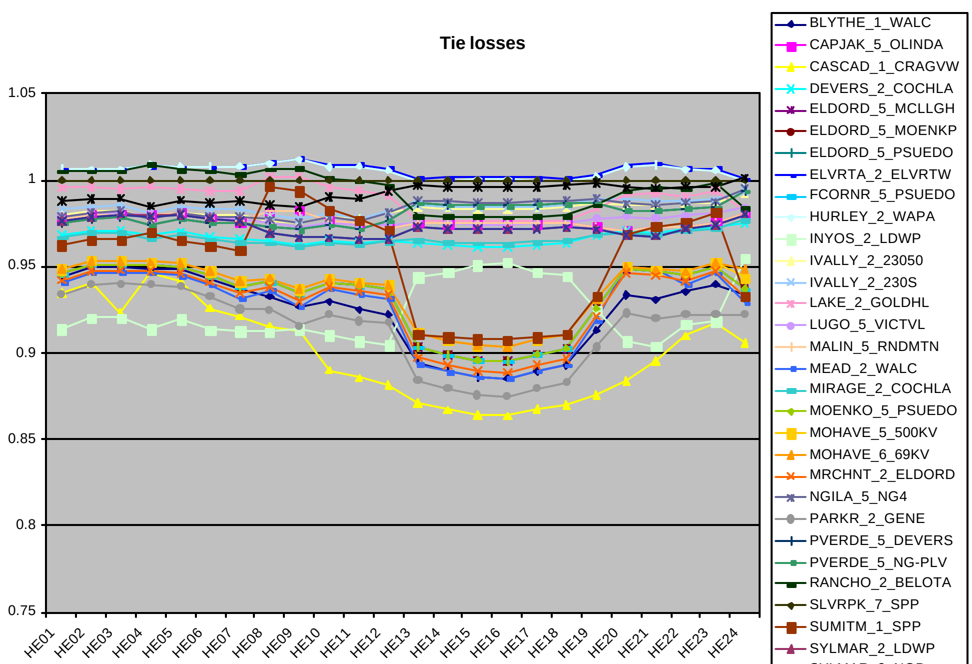
Attachment 1

California ISO

The CAISO allocates losses to generation and imports by way of a Generation Meter Multiplier (GMM) calculated for each interconnection point (generator or interconnect bus) and applied to all energy received at that point. GMMs are estimated a week ahead and then recalculated on a day ahead and finally a real time basis. Real time GMMs are used for all settlement. The Scheduling Protocol describes the following methodology for calculating GMMs:

> (a) The ISO Power Flow Model will be utilized to calculate the effects on total Transmission Losses at each Generating Unit and Scheduling Point by calculating the sensitivity of injecting Energy at each Generating Unit bus or Scheduling Point to **serve an increment of Demand distributed proportionately throughout the ISO Control Area.** This will produce the Full Marginal Loss Rate at each Generating Unit and Scheduling Point.
>
> (b) The ISO will then determine the ratio of expected Transmission Losses to the total Transmission Losses that would be collected if Full Marginal Loss Rates were utilized to determine Transmission Losses. This ratio is referred to as the Loss Scale Factor.
>
> (c) The ISO will then multiply the Loss Scale Factor by the Full Marginal Loss Rate at each Generating Unit or Scheduling Point to determine each Generating Unit's or external import's Scaled Marginal Loss Rate. The GMM is calculated by subtracting the Scaled Marginal Loss Rate from unity.

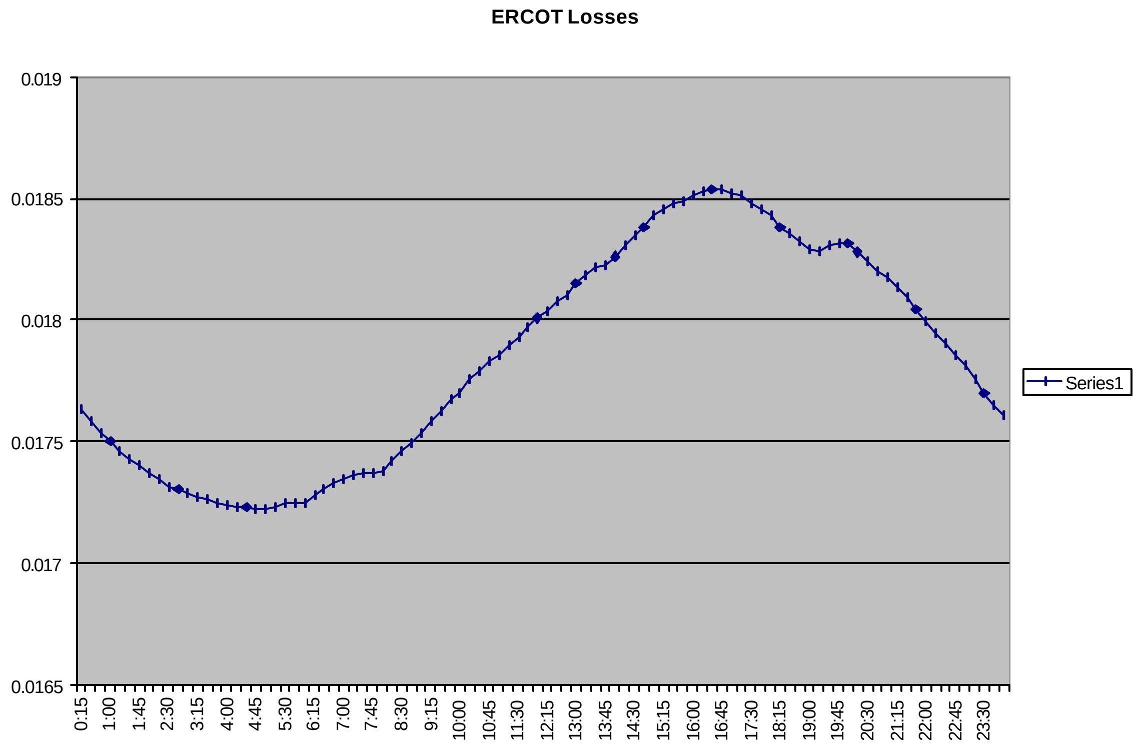
Thus each generating facility and ISO import point is assigned losses for every hour based on their marginal loss contribution scaled for actual losses. Suppliers can provide their losses physically (by applying their GMMs to their actual output) or financially (by ignoring their GMMs and making up the difference as imbalance energy). GMMs can be greater than or less than unity (allowing for negative losses). The chart below shows intertie GMMS for one day.



Attachment 2

ERCOT

ERCOT applies a single loss factor to all transactions each 15 minute interval. The loss factor varies by system load and is scaled to seasonal peak and off peak loss calculations taken from the base case load flow. Loss factors are forecasted day ahead and deemed actual based on total load. Any discrepancies between actual losses and deemed losses is allocated to unaccounted for energy and uplifted. A one day example is shown below.



Attachment 3

Method of accounting for System Losses in NYISO

At any given moment, the generation produced in NY is balanced against the total "load". This "Load" is made up of the actual load as delivered to the distribution system, the net interchange to or from the control area, and transmission system losses (we assume distribution system losses are a part of the distribution load). The distribution load and the net interchange are financially accounted for via either the LMP spot market mechanism or bilateral transaction agreements. However, the losses represent generation that is consumed that no one is otherwise paying for. Therefore, the market operator needs a mechanism to recover enough revenue to pay for the generation needed to account for losses.

Without getting too technical, the computation of locational prices involves choosing an arbitrary location (preferably near the electrical "center" of the system) called the Reference Bus. The major component of any locational price is the incremental cost of producing the next megawatt at the Reference Bus. Assuming for the moment that there is no congestion in the system, the only difference between the LMP at the reference bus and the LMP at some generator elsewhere in the system is a loss component. That difference is equal to the difference in cost for producing that next mw at the reference bus and producing it at the generator bus. If the generator is in such a location as to increase system losses by producing that next mw (i.e. upstream of the reference bus with respect to the predominant power flow at that instant) then the loss component will be in a direction such as to lower the net LMP at the generator. This is because the generator is not quite as valuable as some others might be because it is increasing losses. If the generator is downstream of the reference bus, it will set up a counter flow with respect to the predominant flow and actually reduce system losses slightly by generating that next MW. The difference in production cost is therefore added to his LMP since he is more valuable.

Now the transmission usage charge for transactions is computed by taking the difference between the LMP at the point of withdrawal and the LMP at the point of injection. This process nets out the effect of the location of the reference bus and results in the incremental cost of delivering the next mw from the POI to the POW. Multiplying this cost by the number of MW in the transaction gives the total loss payment.

Note that the LMP is computed for a specific location at a specific moment in time and for the conditions existing at that moment, not on average conditions for a "typical" load on a "typical" day. If the transaction is in the direction of predominant flow, the losses will be relatively high. If the transaction is in a direction normal to predominant flow, the losses may be negligible. If it is in a counter flow direction, the losses will be negative and the customer will be paid!

System losses increase in a quadratic fashion with increasing load. If you imagine all of the users of the system in a stack, those near the top are contributing at a higher rate than those near the bottom. Since the LMP system does not grant priorities of any kind, then the order in this "stack" cannot be determined. Therefore, everyone in the stack gets charged at the marginal rate – the rate for the next MW added to the system. This results in the market operator collecting more revenue than is necessary to purchase the energy accounted for by system losses. The over collection in NYISO is credited to the loads as a discount on their uplift charge (the charge from which the market operator derives his operating revenue).

Attachment 4

Flow Based Zonal Loss Calculations

November 4, 2002

Background

The existing control areas cover losses internally as imbalance energy to maintain net Intertie schedules. Difference between actual net interchange and scheduled net interchange is maintained in an inadvertent energy balance account.

Losses external to the control area are pay by contracts or agreements based on the schedules. These losses are paid financially or in kind.

Each control area has to have revenue grade metering at Interties to account for the flows.

We have multiple areas with different loss factors, used by loads located within and outside of each area. Power flows through areas and from one area to another. This makes the allocation of losses more difficult and variable based on system operations.

Proposal

Use zones with adequate metering (old control areas or new areas) as "common loss" areas and to allocate losses in each zone on pro-rata bases between internal load and external load. Allocate losses external to a zone by net real time flows between zones at a calculated real time loss factor or an established zone loss factor.

Discussion

The RTO West Control Center will require real time data from all zonal boundary ties to track operation of the system.

Each Zone can have an inadvertent energy, which is subject to clearing at some market price.

Correct market signals include indications from the total variable costs of the electrical system. Energy prices, ancillary services, losses, and transmission usage should all be in a good market signal. To keep the signals of equal meaning and not to distort the market, they should also be on the same time frame. Losses allocation should be calculated on a short time frame, 5 minutes was proposed in the SMD NOPR, to provide cost signals to the users of the external zones. High frequency of the signal is important to uses of external zones for their evaluation of the economics of using external energy resources.

Most zones have an established loss factor for transmission losses. The existing factor or a new real time calculation from the RTO, with the net flows between zones can be used to determine the allocation of losses across each zone.

Granularity of the total transmission system into multiple zones should not change the resulting cost to use the transmission system. Zones are dynamic and can be created by new construction or merged. The effect of using multiple zones does not lower the amount of system used or its losses. If the electrical system was divided into ten times the number of areas we currently have, it would fine tune what parts of the system (and associated losses) were actual used. But, at some point the calculation would loss the interdependences of the lines or capacity that are required in the system, but do not have flow. The existing zones (control areas) with different losses is a viable starting point.

Scheduling Coordinators should have the option to propose to RTO West new zones that meet all requirements.

Cost of losses in a source zone (exporting) should be past on to the zones next to it, and then the cost of the new zone with the cost from previous zone are past on to the next zone until the using zone (importing) is found. This is the user paying for its use of the whole system. Real time losses are best for this calculation to prevent any artificial increase in the cost to use the system.

Analysis

The calculation sequence is:

1) Compute the total zonal load from each SC in the zone using the forecasted load or real time actual or calculated load for each SC. Compute the total transmission losses in each zone (part of power flow solution).

2) Compute the export of losses based on the forecasted or actual net export to adjacent zones, the pro-rata share of the total zone load and the net interchange to adjacent zones, and the total zone loss of the source zone.

3) (Re-)Compute the through losses for each zone. Find the smaller quantity of net Import or net Export for each zone (this is the through flow) for the given period and apply the average loss factor for the zone (established or calculated).

4) Compute a new total export of losses for each zone by adding the export (which does not change during these calculations) and the through losses.

5) Repeat step 3 and 4 (the same number of times as there are zones in the system).

Steps 1 and 2 compute the internal and export allocation of losses without any through losses. The solution will show losses to and from each zone in the system. The iterations are required for a loss at one end of the system to migrate to the other end if it has to. The zones with no external transmission use, only have internal losses.

Attachment 5

Strawman Proposal for RTO West Loss Allocation on a PTO/SC basis

Objective is to devise a simple and effective method for RTO West to recover the cost (or volume) of its system losses from Scheduling Coordinators. The method should avoid significant cost shifts among PTOs (acting as SCs for their unconverted customers) and between them and their customers. And it must fit with the Stage II billing & settlements presumption, that only SCs are financially accountable to RTO West for the costs incurred by their schedules.

Assuming that the vast majority of existing contract-holders and load serving entities do not convert to RTO West service, RTO West will initially have to deal with the 10 PTOs acting as SCs for their customers. These customers will either have (pre-888) contract terms that specify how losses will treated and recovered, or they will be charged for losses via the PTO's tariff terms. Obviously these terms do not account for all the actual losses incurred at any one time – they are based on an average loss factor, estimated and published, and periodically adjusted (at best annually) to reflect actual losses in the PTO's control area. In practice, the PTO's own generation in its control area makes up the difference between the actual losses incurred and any losses energy delivered by the PTOs' contract customers, with the PTO recovering the extra cost of this generation via its [transmission? energy?] tariff.

One facet of the present arrangement that must change with RTO West's inception is that each PTO will give up its control area and RTO West will control the generation to meet the difference between actual losses and the loss energy delivered by the PTOs acting as SCs. For the customers' right to voluntary conversion to RTO West service to be meaningful, we must not impose unnecessary changes to or interfere with the arrangements between the PTOs and their customers. Equally we should not impose a cost shift onto PTOs that they cannot recover from their customers.

What all this points to is that RTO West will have to develop a loss factor that applies to each PTO acting as an SC that allows it to recover (either in $$ or MWh) an appropriate share of RTO West system losses from the PTO, and that further allows the PTO to recover such losses either via explicit contract terms or via its tariff. Such loss factors would be *ex ante*, would be fixed for a reasonable period of time (say, six months or a year), and would apply to all CTR-covered schedules submitted by the PTO. RTO West must also develop a loss factor to apply to SCs who submit non-CTR schedules (of which more later).

As already proposed, the SC may deliver its allocated share of losses (by adjusting its scheduled injections[1]) or pay for these via an adjustment to its imbalance energy account at RT prices, or any combination of the two. Since SC loss factors will be published, separate accounting or tagging of loss energy is not essential, but may be administratively convenient.

How does RTO West estimate the applicable loss factor?

[1] I am coming to the view that loss factors should be applied at injection points only (generators and imports), for several reasons: (i) it reflects existing practice (loads don't shrink because of losses); (ii) it will minimize the corrections needed for loads at the withdrawal points; and (iii) it simplifies energy imbalance accounting and forecasting of loads. I am also becoming convinced by arguments that the loss factor should adjust the meter reading (and not the schedule) at the physical injection – avoiding any confusion over loss adjustments for MW dispatched by RTO West (for AS and imbalance), and avoiding double-charging for SC-SC trades.

I propose that when RTO West and the PTOs are testing the adequacy of their CM Assets to support their claimed CTRs (which will require modeling of the expected exercise of CTR schedules over a representative number of hours), RTO West can use this data to analyze the expected system losses and estimate the PTO's share, leading to an *ex ante* loss factor for each PTO which becomes the basis for their tariff loss factor. 'Non-standard' contractual loss factors and recovery arrangements can be taken into account in setting the PTO's tariff loss factor, which will apply to all other CTR-covered schedules submitted by the PTO's as SC for its non-converted customers. The calculation can be revised periodically, simultaneously with the CM Asset adequacy test.

As for an SC's loss factor for non-CTR schedules, I suggest that this be set at the average RTO West loss factor, as until the specific injection points for these are defined for a particular SC, it's difficult to see what other factor could be published (presumably the SC has to offer standard terms to non-CTR clients). An alternative (that the SC apply its allocated tariff loss factor to non-CTR schedules) is administratively simpler, but could lead to gaming and to cost shifts between SCs.

What should be the duration of this arrangement?

Like any other part of our CM model, it is open to RTO West to review, and if appropriate, change the details of the Loss Recovery scheme. I suggest however that this scheme should in any case last no longer than the Company Rate Period, and a review date be set to permit an orderly and planned transition to an alternative scheme no later than the end of the Company Rate Period.

RTO West Loss Error Account

Given the inherent imprecision of *ex ante* loss factors, it is inevitable that the losses recovered under this scheme (MWh or $$) will not match the actual system losses on an hourly basis, and that RTO West will have to dispatch (and pay for) extra generation in order to cover the mismatch. The RTO must therefore be allowed to run a 'Loss Error' account (analogously with the position of a PTO today). This would be limited to some agreed annual figure (in MWh or $$), and RTO West must have scope to adjust the allocated loss factors if it would otherwise overshoot the limit.