Marginal Losses
Implementation Training

Winter and Spring 2007
Training Objectives

• Explain the factors impacting Transmission MW losses
• Describe changes to the LMP calculation as a result of the implementation of Marginal Losses
• Review the possible impacts on generation dispatch as a result of marginal losses
• Analyze the impact of Marginal Losses on Market Settlement through the use of business examples
• Discuss PJM Application and process changes as a result of Marginal Loss implementation
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-Out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
Transmission Losses
Definition
• **Real Power (MW) Losses**
  - Power flow converted to heat in transmission equipment
  - Heat produced by current ($I$) flowing through resistance ($R$)
  - Losses equal to $I^2R$
  - Heat loss sets the “thermal rating” of equipment
Transmission Losses

- **Real Power (MW) Losses**
  - Increase with line length
    - Increased R
  - Increase with increased current flow (I)
  - Increase at lower voltages
    - Higher currents

\[
\text{Power} = \text{Current} \times \text{Voltage}
\]
Power In: 100 MW
Voltage In: 235 KV
Current In: 425.53 A

Power Out: 90.946 MW
Voltage out: 213.72 KV
Current Out: 425.53 A

Power Loss: 9.054 MW
Transmission Losses

Power In: 100 MW
Voltage In: 235 KV
Current In: 425.53 A

Power Out: 98.2 MW
Voltage out: 230.74 KV
Current Out: 425.53 A

Power Loss: 1.8 MW
Transmission Losses

Power In: 100 MW
Voltage In: 525 KV
Current In: 190.47 A

Power Out: 99.637 MW
Power Loss: 0.363 MW
Voltage out: 523.09 KV
Current Out: 190.47 A

10 Miles
• Generation dispatch currently does not take into account the economic effect of losses
  – Results in inefficient dispatch
  – Must produce more MWs resulting in higher prices
• Including losses in dispatch can result in substantial cost savings through reduced *energy* and *congestion* costs
  – PJM studies have estimated savings of $100 million / year
• Total RTO losses on peak days can exceed 3,600 MW/hour
Transmission Losses Today – Prior to Marginal Loss Implementation

• Point-to-Point Transmission Losses
  – Day-Ahead Loss charges
  – Balancing Loss charges
  – Loss credits

• Network customers pay losses through PJM Interchange Energy Market
  – Delivered energy = load plus losses
Point-to-Point Transmission Losses Charge – Prior to Implementation of Marginal Losses

Day-Ahead Charge

- Product of:
  - transaction MWh
  - pre-determined loss factors
  - day-ahead PJM “load” weighted-average LMP

Balancing Charge

- Product of:
  - transaction MWh deviation
  - pre-determined loss factors
  - real-time load weighted-average LMP for all load busses in PJM

Separate loss factors for on-peak (3%) and off-peak periods (2.5%)
Point-to-Point Transmission Losses Credit – Prior to Implementation of Marginal Losses

**Day-Ahead Transmission Loss Charges**

**Balancing Transmission Loss Charges**

**Transmission Loss Credit**

**LSEs**

Allocation based on hourly real-time load ratio shares
Transmission Loss Definition - Summary

• MW Losses are caused by current (I) flowing through resistance (R)
• Losses increase with:
  – Lower voltage
  – Longer lines
  – Higher current
• Not factoring losses into the economic dispatch leads to a less than optimal generation dispatch
Marginal Loss Calculation
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
Economic Dispatch Without Losses

- Incremental Cost for each unit
  \[ \frac{\Delta C}{\Delta P} \] (where C is unit cost and P is the MW Power)

- Unit Cost (total)
  \[ C_T = C_1(P_1) + C_2(P_2) + \ldots + C_n(P_n) \]

- Power Balance
  \[ P_1 + P_2 + \ldots + P_n = P_T \]

Ignoring congestion, the economic dispatch which minimizes cost is when all units operate at the same incremental cost, \( \lambda \)

\[
\lambda = \frac{\Delta C_1}{\Delta P_1} = \frac{\Delta C_2}{\Delta P_2} = \ldots = \frac{\Delta C_n}{\Delta P_n}
\]
Economic Dispatch With Losses

- $P_R$ = Power Received by Customers
- $P_L$ = Transmission Line Losses
- $P_T = P_R + P_L$
- Power Balance (ignoring interchange)
  \[ P_1 + P_2 + \ldots + P_n = P_R + P_L \]
- Unit Cost (total)
  \[ C_T = C_1(P_1) + C_2(P_2) + \ldots + C_n(P_n) \]

The Economic Dispatch still minimizes cost but we need a means to include the effect of losses
• Express Losses, $P_L$, as a function of generation
  $P_L = P_L(P_1, P_2, \ldots, P_n)$
• As individual generators change, the amount of losses will either increase (+) or decrease (-)
• The Incremental Loss for Bus $i$ is the change in system losses due to a change in generation at Bus $i$

$$\frac{\Delta P_L}{\Delta P_i} = \frac{\text{Change in Losses}}{\text{Change in Unit MW Output}}$$
• The Incremental Loss for bus $i$ is used to calculate a factor that can be used to include the effect of losses in the dispatch
• This factor is called the Loss Penalty Factor, or *Penalty Factor*

$$Pf_i = \frac{1}{\left(1 - \frac{\Delta P_L}{\Delta P_i}\right)}$$

• The Penalty Factors modify the incremental cost of each generator so as to include the effects of losses
• Penalty factors applied to each and every location
  – Including generation, load, virtual transaction
• If an increase in generation results in an **increase** in losses then:
  – Penalty factor is *greater* than 1
  – Units offer curve is adjusted higher
    • Unit offer curve is multiplied by penalty factor
    • Unit looks *less* attractive to dispatch

\[
0 < \frac{\Delta P_L}{\Delta P_i} < 1
\]

\[
P_{fi} = \left( 1 - \frac{\Delta P_L}{\Delta P_i} \right) > 1.0
\]
• If an increase in generation results in a decrease in losses then:
  – Penalty factor is less than 1
  – Units offer curve is adjusted lower
    • Unit offer curve is multiplied by penalty factor
    • Unit looks more attractive to dispatch
    • Total LMP would still at least equal unit’s original offer

\[
0 > \frac{\Delta P_L}{\Delta P_i} > -1
\]

\[
P_{fi} = \frac{1}{1 - \frac{\Delta P_L}{\Delta P_i}} < 1.0
\]
Penalty Factors will also impact LMP

- Penalty factor < 1 leads to higher LMP (decreases losses)
- Penalty factor > 1 leads to lower LMP (increases losses)

LMPs will vary by location even in unconstrained operations
LMP = \text{Generation Marginal Cost} + \text{Transmission Congestion Cost} + \text{Cost of Marginal Losses}

\text{Generation Marginal Cost} \ast \left( \frac{1}{Pf} - 1 \right)
• System Energy Price
  – Represents optimal dispatch ignoring congestion and losses
  – Same price for every bus in PJM
  – Used to price Spot Market Interchange
    • Spot Market buyer pays system energy price
    • Spot Market seller is paid system energy price
  – Calculated both in day ahead and real time
LMP Components

LMP = System Energy Price + Congestion Price + Loss Price

• Congestion Price
  – Represents price of congestion for binding constraints
    • Calculated using cost of marginal units controlling constraints and sensitivity factors on each bus
    • No change in this calculation
  – Will be zero if no constraints
    • Will vary by location if system is constrained
  – Used to price explicit and implicit congestion (Locational Net Congestion Bill)
    • Load pays Congestion Price
    • Generation is paid Congestion Price
    • Congestion revenues allocated as hourly credits to FTR holders
  – Calculated both in day ahead and real time
LMP = System Energy Price + Congestion Price + Loss Price

- Loss Price
  - Represents price of marginal losses
    - Calculated using penalty factors as previously described
  - Will vary by location
  - Used to price explicit and implicit losses (Locational Net Loss Bill)
    - Load pays the Loss Price
    - Generation is paid the Loss Price
    - Loss revenues are allocated based on load + exports ratio share
  - Calculated both in day-ahead and real-time
Marginal Loss Example

Losses = 0.0 MW

System Energy Price = 10.00 $/MWh
Loss Price = 0.00 $/MWh
LMP = 10.00 $/MWh

AGC ON

0 MW
PF = 1.00

System Energy Price = 10.00 $/MWh
Loss Price = 0.00 $/MWh
LMP = 10.00 $/MWh

AGC ON

200 MW

Bus 1 Generator Incremental Cost Curve

Bus 2 Generator Incremental Cost Curve
Marginal Loss Example

System Energy Price = 10.00 $/MWh
Loss Price = 0.00 $/MWh
LMP = 10.00 $/MWh

Losses = 2.1 MW

System Energy Price = 10.00 $/MWh
Loss Price = 0.21 $/MWh
LMP = 10.21 $/MWh

PF = 1.00
PF = 0.98

AGC ON

202 MW

500 MW

300 MW

AGC ON

Bus 1 Generator Incremental Cost Curve

Bus 2 Generator Incremental Cost Curve
Marginal Loss Example

Losses = 6.4 MW

System Energy Price = 20.00 $/MWh
Loss Price = 0.83 $/MWh
LMP = 20.83 $/MWh

PF = 1.00
PF = 0.96

AGC ON

Bus 1 Generator Incremental Cost Curve
Bus 2 Generator Incremental Cost Curve
• Penalty factors are calculated based on transmission characteristics, generation levels and load levels
• PJM will utilize a Distributed Loss Reference for Marginal Loss implementation
• Distributed Loss Reference uses the “center” of load as the reference point
  – Electrical center of load
  – Shifts with load
    • Moves with State Estimator calculation
  – Minimizes
    • Error caused by the linearization of the loss model
    • Un-hedgeable loss component
• Penalty factors are calculated for each bus based on effect of an injection at that bus on total system losses.
• Penalty factors are used to modify the incremental cost of each generator to include the impact of losses.
• LMPs will include the effect of marginal losses and will vary across PJM even in unconstrained situations.
• LMP will be shown as three components:
  – System Energy Price
  – Loss Price
  – Congestion Price
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
• Money collected from Marginal Losses will be approximately twice that collected from average losses

• More money collected from load than is paid to generation
  – Results in a loss surplus
    • Estimated to be about $35,000-$55,000 per hour
      – $308-$485 million per year
  – Distributed to Transmission Users based on load + exports ratio shares
• Loss surplus is allocated to Transmission Users

\[
\text{Loss Credit} = \frac{\text{Total Loss Surplus (\$)}}{\text{Total PJM MWh of energy delivered to load + exports}} \times \text{Customer total MWh of energy delivered to load + exports}
\]
### Loss Surplus - Example

<table>
<thead>
<tr>
<th>Load Bus</th>
<th>MWh</th>
<th>Loss Price + System Energy Price</th>
<th>Load Charges</th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td>223</td>
<td>$14.61</td>
<td>$3258.03</td>
</tr>
<tr>
<td>C</td>
<td>223</td>
<td>$14.69</td>
<td>$3275.87</td>
</tr>
<tr>
<td>D</td>
<td>223</td>
<td>$14.33</td>
<td>$3195.59</td>
</tr>
</tbody>
</table>

**PJM collects $9729.49 in energy + loss charges from load.**

<table>
<thead>
<tr>
<th>Generator</th>
<th>Bus</th>
<th>MWh</th>
<th>Loss Price + System Energy Price</th>
<th>Generator Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brighton</td>
<td>E</td>
<td>600</td>
<td>$13.83</td>
<td>$8298</td>
</tr>
<tr>
<td>Alta</td>
<td>A</td>
<td>86</td>
<td>$14.00</td>
<td>$1204</td>
</tr>
<tr>
<td>Park City</td>
<td>A</td>
<td>0</td>
<td>$14.00</td>
<td>$0</td>
</tr>
<tr>
<td>Solitude</td>
<td>C</td>
<td>0</td>
<td>$14.69</td>
<td>$0</td>
</tr>
<tr>
<td>Sundance</td>
<td>D</td>
<td>0</td>
<td>$14.33</td>
<td>$9502</td>
</tr>
</tbody>
</table>

**PJM pays $9502 in energy + loss credits to generation.**

**Surplus of $227.49 is the Loss Revenues.**
## Loss Surplus Allocation

<table>
<thead>
<tr>
<th>Load Bus</th>
<th>MWh</th>
<th>LSE</th>
<th>Loss Surplus Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td>223</td>
<td>ABC</td>
<td>((223/669)($227.49) = $75.83)</td>
</tr>
<tr>
<td>C</td>
<td>223</td>
<td>XYZ</td>
<td>((446/669)($227.49) = $151.66)</td>
</tr>
<tr>
<td></td>
<td>669</td>
<td></td>
<td>($227.49)</td>
</tr>
</tbody>
</table>
• Implementation of Marginal Losses results in a surplus of loss charges collected
• This surplus is allocated to Transmission Users based on load plus exports ratio ratio shares
Business Examples
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
• The following example will illustrate the calculations for:
  – Spot Market Energy (DA and Balancing)
  – Implicit Congestion (DA and Balancing)
  – Implicit Losses (DA and Balancing)
  – Explicit Congestion (DA and Balancing)
  – Explicit Losses (DA and Balancing)
  – FTR Target Allocations
• Participant ABC is engaged in the following activities:
  – Virtual trading (Inc/Dec)
    • Inc bus A; Dec bus D
  – Generation Owner
    • Alta, Solitude
  – Load Serving Entity
    • Day-ahead Demand at bus C
  – Internal Bilateral Transaction
    • Bus E to Bus C
  – FTR holder
    • Bus E to Bus C
    • Bus A to Bus C
Business Example – Day-Ahead Market

Energy LMP = 10.00 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.00 $/MWh
Total LMP = 10.00 $/MWh
PF = 1.00

Brighton
Bid=$10

586 MW
AGC ON

230 MW

225 MW

100%
MVA

100 MW eSchedule E-C

80 MW FTR E-C

50 MW FTR A-C

110 MW
AGC ON

Altair
Bid=$14

Park City
Bid=$15

10 MW
Inc

DA Gen

DA Demand

Energy LMP = 10.00 $/MWh
Congestion LMP = 4.52 $/MWh
Losses LMP = 0.12 $/MWh
Total LMP = 14.66 $/MWh
PF = 0.99

Sundance
Bid=$30

45 MW
AGC ON

10 MW
Dec

300 MW

362 MW

164 MW

395 MW

225 MW

200 MW

295 MW

70 MW

162 MW

132 MW

130 MW

Energy LMP = 10.00 $/MWh
Congestion LMP = 10.93 $/MWh
Losses LMP = 0.55 $/MWh
Total LMP = 21.48 $/MWh
PF = 0.95

Solitude
Bid=$31
Day-Ahead Spot Market Energy Calculation

Day-Ahead Spot Market Energy

Day-Ahead Load MWh
Day-Ahead Decrement Transaction MWh
Day-Ahead Sale Transaction MWh

NET

- Day-Ahead Generation MWh
- Day-Ahead Increment Transaction MWh
- Day-Ahead Purchase Transaction MWh

+
Day-Ahead Spot Market Energy

Buyer Charges

System Energy Price

Seller Charges (negative)

Day-Ahead System Energy Price

System Energy Price will be the same for all participants.
### Business Example – Day-Ahead Spot Market Energy

<table>
<thead>
<tr>
<th>Energy Market Withdrawals</th>
<th>Energy Market Injections</th>
</tr>
</thead>
<tbody>
<tr>
<td>200 MW (DA Demand)</td>
<td>100 MW (eSchedule purchase)</td>
</tr>
<tr>
<td>10 MW (Decrement Bid)</td>
<td>110 MW (Alta day-ahead schedule)</td>
</tr>
<tr>
<td></td>
<td>10 MW (Increment Offer)</td>
</tr>
<tr>
<td></td>
<td>0 MW (Solitude day-ahead schedule)</td>
</tr>
</tbody>
</table>

| 210 MW                    | 220 MW                      |

\[
210 \text{ MW} - 220 \text{ MW} = -10 \text{ MW} \times $10.00 = -$100 \text{ charge}
\]

(Note that charge is negative)

**Day-Ahead System Energy Price**
Locational Net Congestion Bill is the difference in congestion prices between a participant’s energy market withdrawals and injections

**Net Congestion Bill:**

Congestion Withdrawal Charges - Congestion Injection Credits

**Congestion Withdrawal Charges**:  
- Load: Load Bus MWh x *Congestion Price* at Load Bus  
- Energy Sales: Sale MWh x *Congestion Price* at Source  
- Decrement Bids: Dec Bid MWh x *Congestion Price* at Bus

**Congestion Injection Credits**:  
- Generation: Gen Bus MWh x *Congestion Price* at Gen Bus  
- Energy Purchases: Purchase MWh x *Congestion Price* at Sink  
- Increment Offers: Offer Bid MWh x *Congestion Price* at Bus

*deviations are used for balancing market calculations*
# Business Example – Day-Ahead Implicit Congestion

<table>
<thead>
<tr>
<th>Congestion Withdrawal Charges</th>
<th>Congestion Injection Credits</th>
</tr>
</thead>
<tbody>
<tr>
<td>200 MW (DA Demand) * $13.24 = $2648</td>
<td>100 MW (eSchedule purchase) * $13.24 = $1324</td>
</tr>
<tr>
<td>10 MW (Decrement Bid) * $19.62 = $196.20</td>
<td>110 MW (Alta DA schedule) * $4.52 = $497.20</td>
</tr>
<tr>
<td></td>
<td>10 MW (Increment Offer) * $4.52 = $45.2</td>
</tr>
<tr>
<td></td>
<td>0 MW (Solitude DA schedule) * $13.24 = $0</td>
</tr>
<tr>
<td>$2844.20</td>
<td>$1866.40</td>
</tr>
</tbody>
</table>

$2844.20 - $1866.40 = $977.80 charge

Prices are day-ahead congestion prices at corresponding locations.
Locational Net Loss Bill is the difference in loss prices between a participant’s energy market withdrawals and injections

**Net Loss Bill:**
Loss Withdrawal Charges – Loss Injection Credits

**Loss Withdrawal Charges***:
Load: Load Bus MWh x Loss Price at Load Bus
Energy Sales: Sale MWh x Loss Price at Source
Decrement Bids: Dec Bid MWh x Loss Price at Bus

**Loss Injection Credits***:
Generation: Gen Bus MWh x Loss Price at Gen Bus
Energy Purchases: Purchase MWh x Loss Price at Sink
Increment Offers: Inc Offer MWh x Loss Price at Bus

* deviations are used for balancing market calculations
### Business Example – Day-Ahead Implicit Losses

<table>
<thead>
<tr>
<th>Loss Withdrawal Charges</th>
<th>Loss Injection Credits</th>
</tr>
</thead>
<tbody>
<tr>
<td>200 MW (DA Demand) * $0.60 = $120</td>
<td>100 MW (eSchedule purchase) * $0.60 = $60</td>
</tr>
<tr>
<td>10 MW (Decrement Bid) * $0.38 = $3.80</td>
<td>110 MW (Alta DA schedule) * $0.12 = $13.20</td>
</tr>
<tr>
<td></td>
<td>10 MW (Increment Offer) * $0.12 = $1.20</td>
</tr>
<tr>
<td></td>
<td>0 MW (Solitude DA schedule) * $0.60 = $0</td>
</tr>
<tr>
<td><strong>$123.80</strong></td>
<td><strong>$74.40</strong></td>
</tr>
</tbody>
</table>

$123.80 - $74.40 = $49.40 charge

Prices are day-ahead loss prices at corresponding locations.
Business Example – Day-Ahead Explicit Congestion

- Transmission customer pays congestion for external transactions
- Buyer pays congestion for internal transactions (network customer)

100 MW (eSchedule purchase) * ($13.24 - $0) = $1,324 charge
Business Example – Day-Ahead Explicit Losses

- Transmission customer pays losses for external transactions
- Buyer pays losses for internal transactions (network customer)

\[
100 \text{ MW (eSchedule purchase)} \times (\$0.60 - \$0) = \$60 \text{ charge}
\]
FTR Target Allocation = FTR MW * (Day-Ahead Congestion Price at Sink - Day-Ahead Congestion Price at Source)

FTR #1 Target Allocation = 80 MW ($13.24 - $0) = $1,059.20
FTR #2 Target Allocation = 50 MW ($13.24 - $4.52) = $436.00
Business Example – Balancing Market

Energy LMP = 11.75 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.00 $/MWh
Total LMP = 11.75 $/MWh
PF = 1.00

Brighton
Bid=$10
600 MW
AGC ON

Energy LMP = 11.75 $/MWh
Congestion LMP = 17.81 $/MWh
Losses LMP = 0.44 $/MWh
Total LMP = 30.00 $/MWh
PF = 0.96

100 MW eSchedule E-C

RT Gen

RT Demand

110 MW
AGC ON
Alta
Bid=$14

82 MW
AGC ON
Park City
Bid=$15

390 MW

161 MW

392 MW

230 MW

225 MW

159 MW

197 MW

220 MW

250 MW

63 MW
AGC ON

Sundance
Bid=$30

Energy LMP = 11.75 $/MWh
Congestion LMP = 3.10 $/MWh
Losses LMP = 0.15 $/MWh
Total LMP = 15.00 $/MWh
PF = 0.99

99%

370 MW

368 MW

10 MW

37 MW
AGC ON

380 MW

220 MW

400 MW

100%
Balancing Spot Market Charges

\[ \text{Balancing Spot Market Charges} = \left( \text{Real-Time Net Interchange (MWh)} \right) - \left( \text{Day-Ahead Net Interchange (MWh)} \right) \times \text{Real-Time System Energy Price ($/MWh)} \]

- Charge amounts may be either positive (+) or negative (-), depending on the difference between Day-Ahead and Balancing Interchange MWh.
## Business Example – Balancing Spot Market Energy

<table>
<thead>
<tr>
<th>Real-Time Energy Withdrawals</th>
<th>Real-Time Energy Injections</th>
</tr>
</thead>
<tbody>
<tr>
<td>220 MW (RT Load excluding losses)</td>
<td>100 MW (eSchedule purchase)</td>
</tr>
<tr>
<td></td>
<td>110 MW (Alta actual generation)</td>
</tr>
<tr>
<td></td>
<td>37 MW (Solitude actual generation)</td>
</tr>
<tr>
<td><strong>220 MW</strong></td>
<td><strong>247 MW</strong></td>
</tr>
</tbody>
</table>

220 MW – 247 MW = -27 MW

-27 MW – (-10 MW) = -17 MW ($11.75) = -$199.75 charge

(Note that charge is negative)
Calculation of Locational Net Congestion Bill
(Implicit Congestion)

Locational Net Congestion Bill is the difference in congestion prices between a participant’s energy market withdrawals and injections

**Net Congestion Bill:**
Congestion Withdrawal Charges - Congestion Injection Credits

**Congestion Withdrawal Charges**:
Load: Load Bus MWh x *Congestion Price* at Load Bus
Energy Sales: Sale MWh x *Congestion Price* at Source
Decrement Bids: Dec Bid MWh x *Congestion Price* at Bus

**Congestion Injection Credits**:
Generation: Gen Bus MWh x *Congestion Price* at Gen Bus
Energy Purchases: Purchase MWh x *Congestion Price* at Sink
Increment Offers: Offer Bid MWh x *Congestion Price* at Bus

*deviations are used for balancing market calculations*
### Business Example – Balancing Implicit Congestion

**Congestion Withdrawal Charges**

- \((220 \text{ MW} - 200 \text{ MW})\) (Demand Dev) \(\times \$18.40 = $368.00\)
- \((0 \text{ MW} - 10 \text{ MW})\) (Decrement Dev) \(\times \$17.81 = -$178.10\)

**Congestion Injection Credits**

- \((100 \text{ MW} - 100 \text{ MW})\) (eSchedule purch dev) \(\times \$18.40 = $0\)
- \((110 \text{ MW} - 110 \text{ MW})\) (Alta deviation) \(\times \$3.10 = $0\)
- \((0 \text{ MW} - 10 \text{ MW})\) (Increment Dev) \(\times \$3.10 = -$31.00\)
- \((37 \text{ MW} - 0 \text{ MW})\) (Solitude deviation) \(\times \$18.40 = $680.8\)

<table>
<thead>
<tr>
<th>Congestion Withdrawal Charges</th>
<th>Congestion Injection Credits</th>
</tr>
</thead>
<tbody>
<tr>
<td>(220 \text{ MW} - 200 \text{ MW}) (Demand Dev) (\times $18.40 = $368.00)</td>
<td>((100 \text{ MW} - 100 \text{ MW})) (eSchedule purch dev) (\times $18.40 = $0)</td>
</tr>
<tr>
<td>((0 \text{ MW} - 10 \text{ MW})) (Decrement Dev) (\times $17.81 = -$178.10)</td>
<td>((110 \text{ MW} - 110 \text{ MW})) (Alta deviation) (\times $3.10 = $0)</td>
</tr>
<tr>
<td>(\text{Total} = -$190.00)</td>
<td>(\text{Total} = $649.80)</td>
</tr>
</tbody>
</table>

\(\$190.00 - \$649.80 = -$459.80\) charge

Prices are real-time congestion price at corresponding locations.
Locational Net Loss Bill is the difference in loss prices between a participant’s energy market withdrawals and injections

**Net Loss Bill:**
Loss Withdrawal Charges – Loss Injection Credits

**Loss Withdrawal Charges***:
Load: Load Bus MWh x *Loss Price* at Load Bus
Energy Sales: Sale MWh x *Loss Price* at Source
Decrement Bids: Dec Bid MWh x *Loss Price* at Bus

**Loss Injection Credits***:
Generation: Gen Bus MWh x *Loss Price* at Gen Bus
Energy Purchases: Purchase MWh x *Loss Price* at Sink
Increment Offers: Inc Offer MWh x *Loss Price* at Bus

* deviations are used for balancing market calculations
## Business Example – Balancing Implicit Losses

<table>
<thead>
<tr>
<th>Loss Withdrawal Charges</th>
<th>Loss Injection Credits</th>
</tr>
</thead>
<tbody>
<tr>
<td>(220 MW - 200 MW (Demand Dev)) * $0.86 = $17.20</td>
<td>(100 MW - 100 MW (eSchedule purch dev)) * $0.86 = $0</td>
</tr>
<tr>
<td>(0 MW - 10 MW (Decrement Dev)) * $0.44 = $4.40</td>
<td>(110 MW - 110 MW (Alta deviation)) * $0.15 = $0</td>
</tr>
<tr>
<td></td>
<td>(0 MW - 10 MW (Increment Dev)) * $0.15 = $4.40</td>
</tr>
<tr>
<td></td>
<td>(37 MW - 0 MW (Solitude deviation) * $0.86 = $31.82</td>
</tr>
</tbody>
</table>

$12.80 $30.32

$12.80 - $30.32 = - $17.52 charge

Prices are real-time congestion price at corresponding locations.
• Transmission customer pays congestion for external transactions
• Buyer pays congestion for internal transactions (network customer)

0 MWh (eSchedule purchase deviation) * ($18.40 - $0) = $0
• Transmission customer pays losses for external transactions
• Buyer pays losses for internal transactions (network customer)

\[ 0 \text{ MW (eSchedule purchase deviation)} \times (\$0.86 - \$0) = \$0 \]
Total System Loss Surplus = $123.31  
(total for all participants)

Example Participant’s Transmission Loss Credit =  
($123.31) (220 MW/ 870 MW) = $31.18

Where: 220 MW is hourly real-time load at bus C (example participant) and 870 MW is total system load + zero exports
• Maps/MW Flow Program
• 2005 Annual simulation run (8760 hours)
  – Full transmission model (2004)
  – Production cost simulation using:
    • Production cost database built from RDI basecase (2002/2003 release)
    • Simulates security-constrained unit commitment and Economic Dispatch
    • Includes hourly load forecasts, generation outage schedules, etc
## Simulation Results – Load Price

<table>
<thead>
<tr>
<th>Zone</th>
<th>Change in Zonal Load Price Due to Loss Component ($/MWh) Loss Case – Base Case</th>
<th>Change in Zonal Load Price Due to Congestion Component ($/MWh) Loss Case – Base Case</th>
<th>Load Net Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>$2.21</td>
<td>-$2.37</td>
<td>-$0.16</td>
</tr>
<tr>
<td>AP</td>
<td>$0.23</td>
<td>-$0.24</td>
<td>-$0.01</td>
</tr>
<tr>
<td>BG&amp;E</td>
<td>$1.41</td>
<td>-$2.74</td>
<td>-$1.33</td>
</tr>
<tr>
<td>DPL</td>
<td>$1.91</td>
<td>-$2.53</td>
<td>-$0.62</td>
</tr>
<tr>
<td>GPUE</td>
<td>$2.45</td>
<td>-$2.23</td>
<td>$0.22</td>
</tr>
<tr>
<td>GPUW</td>
<td>$1.30</td>
<td>-$1.43</td>
<td>-$0.13</td>
</tr>
<tr>
<td>PECO</td>
<td>$1.85</td>
<td>-$2.32</td>
<td>-$0.47</td>
</tr>
<tr>
<td>PPL</td>
<td>$1.76</td>
<td>-$2.04</td>
<td>-$0.28</td>
</tr>
<tr>
<td>PEPCO</td>
<td>$0.92</td>
<td>-$2.87</td>
<td>-$1.95</td>
</tr>
<tr>
<td>PSEG</td>
<td>$2.39</td>
<td>-$2.21</td>
<td>$0.18</td>
</tr>
<tr>
<td>RECO</td>
<td>$2.34</td>
<td>-$2.18</td>
<td>$0.16</td>
</tr>
<tr>
<td>AEP</td>
<td>-$0.69</td>
<td>$0.52</td>
<td>-$0.17</td>
</tr>
<tr>
<td>DP&amp;L</td>
<td>-$0.54</td>
<td>$0.45</td>
<td>-$0.09</td>
</tr>
<tr>
<td>VP</td>
<td>$0.74</td>
<td>-$1.52</td>
<td>-$0.78</td>
</tr>
<tr>
<td>COM-ED</td>
<td>-$1.74</td>
<td>$1.06</td>
<td>-$0.68</td>
</tr>
<tr>
<td>DUQ</td>
<td>-$0.55</td>
<td>$0.41</td>
<td>-$0.14</td>
</tr>
</tbody>
</table>
## Simulation Results – Generation Price

<table>
<thead>
<tr>
<th>Zone</th>
<th>Change in Zonal Gen Price Due to Loss Component ($/MWh) Loss Case – Base Case</th>
<th>Change in Zonal Gen Price Due to Congestion Component ($/MWh) Loss Case – Base Case</th>
<th>Generation Net Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>$2.15</td>
<td>-$2.37</td>
<td>-$0.22</td>
</tr>
<tr>
<td>AP</td>
<td>$0.22</td>
<td>-$0.32</td>
<td>-$0.10</td>
</tr>
<tr>
<td>BG&amp;E</td>
<td>$1.37</td>
<td>-$2.75</td>
<td>-$1.38</td>
</tr>
<tr>
<td>DPL</td>
<td>$1.85</td>
<td>-$2.53</td>
<td>-$0.68</td>
</tr>
<tr>
<td>GPUE</td>
<td>$2.39</td>
<td>-$2.24</td>
<td>$0.15</td>
</tr>
<tr>
<td>GPUW</td>
<td>$1.22</td>
<td>-$1.69</td>
<td>-$0.47</td>
</tr>
<tr>
<td>PECO</td>
<td>$1.79</td>
<td>-$2.36</td>
<td>-$0.57</td>
</tr>
<tr>
<td>PPL</td>
<td>$1.69</td>
<td>-$2.17</td>
<td>-$0.48</td>
</tr>
<tr>
<td>PEPCO</td>
<td>$0.90</td>
<td>-$2.69</td>
<td>-$1.79</td>
</tr>
<tr>
<td>PSEG</td>
<td>$2.30</td>
<td>-$2.20</td>
<td>$0.10</td>
</tr>
<tr>
<td>RECO</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>AEP</td>
<td>-$0.66</td>
<td>$0.52</td>
<td>-$0.14</td>
</tr>
<tr>
<td>DP&amp;L</td>
<td>-$0.50</td>
<td>$0.45</td>
<td>-$0.05</td>
</tr>
<tr>
<td>VP</td>
<td>$0.72</td>
<td>-$1.13</td>
<td>-$0.41</td>
</tr>
<tr>
<td>COM-ED</td>
<td>-$1.68</td>
<td>$1.06</td>
<td>-$0.62</td>
</tr>
<tr>
<td>DUQ</td>
<td>-$0.54</td>
<td>$0.41</td>
<td>-$0.13</td>
</tr>
</tbody>
</table>
## Summary of Net Changes

<table>
<thead>
<tr>
<th>Zone</th>
<th>Load Net Change ($/MWh) Loss Case – Base Case</th>
<th>Gen Net Change ($/MWh) Loss Case – Base Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>-$0.16</td>
<td>-$0.22</td>
</tr>
<tr>
<td>AP</td>
<td>-$0.01</td>
<td>-$0.10</td>
</tr>
<tr>
<td>BG&amp;E</td>
<td>-$1.33</td>
<td>-$1.38</td>
</tr>
<tr>
<td>DPL</td>
<td>-$0.62</td>
<td>-$0.68</td>
</tr>
<tr>
<td>GPUE</td>
<td>$0.22</td>
<td>$0.15</td>
</tr>
<tr>
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<td>-$0.13</td>
<td>-$0.47</td>
</tr>
<tr>
<td>PECO</td>
<td>-$0.47</td>
<td>-$0.57</td>
</tr>
<tr>
<td>PPL</td>
<td>-$0.28</td>
<td>-$0.48</td>
</tr>
<tr>
<td>PEPCO</td>
<td>-$1.95</td>
<td>-$1.79</td>
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<tr>
<td>PSEG</td>
<td>$0.18</td>
<td>$0.10</td>
</tr>
<tr>
<td>RECO</td>
<td>$0.16</td>
<td>--</td>
</tr>
<tr>
<td>AEP</td>
<td>-$0.17</td>
<td>-$0.14</td>
</tr>
<tr>
<td>DP&amp;L</td>
<td>-$0.09</td>
<td>-$0.05</td>
</tr>
<tr>
<td>VP</td>
<td>-$0.78</td>
<td>-$0.41</td>
</tr>
<tr>
<td>COM-ED</td>
<td>-$0.68</td>
<td>-$0.62</td>
</tr>
<tr>
<td>DUQ</td>
<td>-$0.14</td>
<td>-$0.13</td>
</tr>
</tbody>
</table>
• **Spot Market Energy** charges (+/-) priced at the System Energy Price

• **Implicit Congestion** charges (+/-) calculated as a locational net congestion bill using the Congestion Price

• **Explicit Congestion** charges (+/-) calculated for transactions using the Congestion Price at source and sink

• **Implicit Loss** charges (+/-) calculated as a locational net loss bill using the Loss Price

• **Explicit Loss** charges (+/-) calculated for transactions using the Loss Price at source and sink
• **FTR Target Allocations** calculated as FTR MW times the difference between the day-ahead congestion prices at the FTR source/sink

• **Loss Surplus** is allocated as credits to Transmission Users based on hourly real-time load + exports ratio share
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-Out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
Implementation of Marginal Losses creates potential for double counting of losses due to:

- EDCs gross up the derived loads measured at individual retail meters to account for losses
  - Based on State-filed retail rates
- PJM Settlement calculations being changed to account for losses using the marginal loss component of LMP

Solution is to calculate the amount of losses that will be included in the LMP value and subtract it from the EDCs’ total load values

- Eliminates double counting potential
- Consistent approach
- Does not require filing new retail rates with States
• Loads will be reduced based on a *hourly* EDC Loss De-ration Factor
  – Determined by state-estimated losses
• For non-PJM Mid-Atlantic EDCs:

\[ f_{\text{loss}} = \frac{\text{Loss}_{\text{EDC-SE}}}{\text{TL}} \]

\[ f_{\text{loss}} = \text{EDC loss de-ration factor} \]
\[ \text{Loss}_{\text{EDC-SE}} = \text{EDC hourly total state-estimated losses} \]
\[ \text{TL} = \text{EDC total revenue-metered load (includes all losses)} \]

• For PJM Mid-Atlantic EDCs:

\[ f_{\text{loss}} = \frac{(\text{Loss}_{\text{EDC non-500kV}} + \text{Loss}_{\text{500kV}})}{(\text{TL} + \text{Loss}_{\text{500kV}})} \]

\[ f_{\text{loss}} = \text{EDC loss de-ration factor} \]
\[ \text{Loss}_{\text{EDC non-500kV}} = \text{EDC total non-500 kV state-estimated losses} \]
\[ \text{Loss}_{\text{500kV}} = \text{EDC revenue-metered 500 kV loss allocation} \]
\[ \text{TL} = \text{EDC total revenue-metered load (includes all losses)} \]
1. EDC determines measured customer load and calculates “bottom-up” total load per existing State-filed procedures

\[ \text{Load}_{\text{metered}} = 11.0 \text{ MW} \]
\[ f_{EDC} = 0.0345 \]

\[ TL_{\text{Bottom-up}} = \text{Load}_{\text{metered}} \times (1 + f_{EDC}) \]
\[ = 11.0 \times 1.0345 \]
\[ = 11.3795 \]

2. EDC submits this Total Load to PJM via eSchedules. Upon receipt, PJM will apply the EDC Loss De-ration Factor in order to de-rate the submitted load by the calculated value of marginal losses included in LMP.

\[ f_{loss} = 0.01255 \]

\[ \text{Loss}_{\text{marginal}} = f_{loss} \times TL_{\text{bottom-up}} \]
\[ = 0.01255 \times 11.3795 \]
\[ = 0.1428 \]

\[ TL_{\text{de-rated}} = TL_{\text{bottom-up}} - \text{Loss}_{\text{marginal}} \]
\[ = 11.3795 - 0.1428 \]
\[ = 11.2367 \]
• Unadjusted Load Reconciliation Value including all losses is submitted to eSchedules (for RLR and WLR eSchedules)
• PJM will apply hourly EDC Loss De-ration Factors to these schedules to de-rate them for losses
• Load Reconciliation MWh (not including losses) will be settled separately using each of the three components of real-time LMP
  – Energy reconciliation charges
  – Congestion reconciliation charges
  – Loss reconciliation charges
• Load Reconciliation MWh for Ancillary Service reconciliations will include or not include losses depending on the applicable settlement calculation for the particular ancillary service
Flow Diagram for Load eSchedules Loss De-Ration

**Initial eSchedule**
Entered into MSET

**First Settlement**
Uses appropriate load values with and without losses

**Reconciliation**
Entered into MSET

**Final Settlement**
Uses appropriate load reconciliation values with and without losses

**Hourly EDC Loss**
De-ration factor applied to full eSchedule

**RLR/WLR eSchedule**
received

**New daily report provides eSchedule load data with and without losses**

**Load + Losses value available from eSchedules interface**

**De-rated reconciliation value available from existing eSchedules reconciliation billing reports**

**RLR/WLR eSchedule Reconciliation received**

**Load + Losses reconciliation value available from eSchedules Reconciliation Data report**

Load without losses value available from RT Daily Transaction report
Load MWh will now exclude Loss MWh (since load pays loss component of LMP)

- LSEs no longer hedge real-time losses in day-ahead demand bid
- LSEs’ real-time load in energy market no longer includes loss MWh
- EDCs’ zonal real-time load will be reduced by state-estimated losses
- PJM Mid-Atlantic 500 kV losses no longer allocated as load
- EDC Loss De-ration Factors will de-rate Retail Load Responsibility (RLR) and Wholesale Load Responsibility (WLR) eSchedules MWh
Zonal EDCs must still report load including losses, for:

- Network service peak loads (NSPLs)
- Capacity peak load contributions (PLCs)
- Load forecasting and zonal reserve requirements

**eMTR load submission screen data will include losses**

- De-rated loss adjustment and final de-rated load will be made available
Load Carve-Out Process Changes - Summary

• To prevent double-counting of losses, PJM will de-rate EDC and LSE load values to account for losses in the marginal loss calculation
  – Will not require changes to existing EDC/LSE processes
  – Participants will be able to see original and de-rated load values through eSchedules and eMTR
• Day-ahead Demand Bids should no longer include losses
• Transmission Losses Definition
• Marginal Loss Calculation
• Surplus Loss Allocation
• Business Examples
• Load Carve-Out Process Changes
• settlements Changes
• PJM Application Changes
• Next Steps
Prior to Marginal Losses Implementation

- Point-to-point transmission customers are charged for transmission losses based on
  - Transaction MWh
  - PJM load-weighted average LMP
  - Loss factor (3% on-peak; 2½% off-peak)

After Marginal Losses Implementation

- This charge (and the associated credit allocation) will be eliminated since losses will be included in the LMPs
- New line items for Transmission Loss charges and credits replace the existing line items
Prior to Marginal Loss Implementation
- Losses on PJM Mid-Atlantic 500 kV system allocated as load to PJM Mid-Atlantic EDCs

After Marginal Loss Implementation
- PJM Mid-Atlantic 500 kV losses will no longer be allocated as load
  - Losses now included in LMP calculation
  - EDC total real-time load will be reduced by state-estimator losses (and revenue-metered 500 kV losses, as applicable)
• Prior to June 1, 2007
  – Inadvertent Interchange energy allocated to EDCs only
    • EDC would further allocate to LSEs in their zone
    • Priced at PJM load-weighted-average LMP

• After June 1, 2007
  – Allocated as +/- charges directly to all LSEs
    • Based on real-time load ratio shares
    • Priced at the PJM load-weighted-average LMP
      – Total LMP (3 components)

Note: This change is unrelated to Marginal Losses, but being implemented at the same time. This change has been approved by FERC for a June 1, 2007 implementation.
• Prior to June 1, 2007
  – Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values

• After June 1, 2007
  – Meter correction charges to account for external tie meter errors
    • Allocated as +/- charges directly to all LSEs
      – Based on real-time load ratio shares
      – Priced at the PJM load-weighted-average LMP
        » Total LMP (3 components)
  – Internal tie, generator, and PJM Mid-Atlantic 500 kV meter correction charges remain with applicable EDCs/Generators

Note: This change is unrelated to Marginal Losses, but being implemented at the same time. This change has been approved by FERC for a June 1, 2007 implementation.
• Prior to Marginal Loss Implementation
  – Obligations/charges for all Ancillary Services was based on load plus losses

• After Marginal Loss Implementation
  – Some Ancillary Services charged based on “Load plus Losses” while others charged based on “Lossless Load”
  – In general:
    • Operating Agreement accounting uses “Lossless Load”
    • OATT accounting uses “Load plus Losses”
  – Terminology:
    • “Load” refers to “Lossless Load” unless specifically called out as “Load plus Losses” in the agreement language
  – Details on next few slides
“Load” for Network Transmission and Capacity Obligation

- **Network Transmission Service**
  - Charged based on Network Service Peak Loads (NSPLs)
    - Based on “Load plus Losses”

- **Capacity Obligation**
  - Based on Peak Load Contributions (PLCs)
    - Based on “Load plus Losses”

No Change
The following Schedule 9 and 10 charges will be charged to “Load plus Losses” transmission use:

- Schedule 9-1
  - PJM Scheduling, System Control and Dispatch Service – Control Area Administration

- Schedule 9-3
  - PJM Scheduling, System Control and Dispatch Service – Market Support

- Schedule 9-FERC
  - FERC Annual Charge Recovery

- Schedule 9-OPSI
  - Organization of PJM States, Inc. (OPSI)

- Schedule 10-NERC
  - North American Electric Reliability Corporation (NERC)

- Schedule 10-RFC
  - ReliabilityFirst Corporation

No Change
• Schedule 1A – Transmission Owner Scheduling, System Control and Dispatch Service
  – Charge to transmission use, where Network load is “Load plus Losses”
• Schedule 2 (Reactive Supply) and Schedule 6A (Black Start Service)
  – Charges allocated to point-to-point and network customers based on transmission usage
  • Network customer load is “Load plus Losses”
• LSE hourly Regulation Obligation based on real-time load ratio share of the total regulation MWh assigned that hour
  – Load for this calculation will be “Lossless Load”

• LMP used in Regulation Market Clearing Price calculation will be total LMP
• PJM Synchronized Reserve Requirements differ by Synchronized Reserve Market Area
• LSE hourly Synchronized Reserve Obligation based on real-time load ratio share of the total synch reserve tier 2 MWh assigned that hour
  – Load for this calculation will be “Lossless Load”

• LMP used in Synchronized Reserve Market Clearing Price calculation will be total LMP
• Day-Ahead Operating Reserve charges allocated to decrement bids, day-ahead exports and cleared day-ahead demand
  – Day-ahead demand assumed to be “Lossless Load”
    • LSEs no longer need to hedge real-time losses in day-ahead demand bid

• Day-Ahead Energy Market revenues for generator operating reserve credit calculation will utilize total LMP
• Balancing Operating Reserve charges allocated to generation (not following dispatch), transaction, and load deviations
  – Load deviations based on “Lossless Load”
    • Compare real-time lossless load to cleared DA demand
• Balancing energy market revenues for generator operating reserve credit calculation will utilize total LMP
• Synchronous Condensing Charge
  – Not for Synchronized Reserve nor Reactive Services
    • Allocated based on real-time load plus export shares
      – Load is real-time “Lossless Load”
• Reactive Services Charge (not Schedule 2)
  – Charges for generators who alter their output to achieve greater reactive capability
    • Allocated separately for each zone based on real-time load ratio shares within applicable zone
      – Load is real-time “Lossless Load”
• Credits for day-ahead and real-time demand reductions
  – PJM will de-rate reduction (previously grossed up for losses) based on EDC Loss De-ration Factor
  – Therefore, credit based on “Lossless load”
• Charges allocated by zonal load ratio shares
  – Based on “Lossless load”
## “Load” for Market Settlements Billing Items - Summary

<table>
<thead>
<tr>
<th>Billing Item Based on “Load + Losses”</th>
<th>Billing Item Based on “Lossless Load”</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Transmission Service</td>
<td>Spot Market Energy (DA and Balancing)</td>
</tr>
<tr>
<td>Capacity Obligation</td>
<td>Congestion (DA and Balancing)</td>
</tr>
<tr>
<td>Schedule 1A- Trans Owner Scheduling, System Control and Dispatch</td>
<td>Regulation Obligation</td>
</tr>
<tr>
<td>Schedule 2 – Reactive</td>
<td>Synchronized Reserve Obligation</td>
</tr>
<tr>
<td>Schedule 6A – Black Start</td>
<td>DA Operating Reserve (DA Demand)</td>
</tr>
<tr>
<td>Schedule 9-1 PJM Control Area Administration</td>
<td>Balancing Operating Reserve (Load deviations)</td>
</tr>
<tr>
<td>Schedule 9-3 PJM Market Support</td>
<td>Synchronous Condensing (for load following and post-contingency operation)</td>
</tr>
<tr>
<td>Schedule 9-FERC</td>
<td>Reactive Services (units reduced to provide more reactive power)</td>
</tr>
<tr>
<td>Schedule 9-OPSI</td>
<td>Load Response</td>
</tr>
<tr>
<td>Schedule 10-NERC</td>
<td>Inadvertent Interchange</td>
</tr>
<tr>
<td>Schedule 10-RFC</td>
<td></td>
</tr>
</tbody>
</table>
• **New** PJM Billing Line Items
  – Transmission Loss charges and credits
  – Transmission Loss Reconciliation charges and credits
  – Transmission Congestion Reconciliation charges
  – Inadvertent Interchange charges

• **Terminated** PJM Billing Line Items
  – Point-to-point Transmission Loss charges and credits
  – Point-to-point Transmission Loss Reconciliation credits
  – Spot Market Energy credits
• **New PJM Settlement Reports**
  – Transmission Loss Charge Summary
  – Explicit Losses Summary
  – Transmission Loss Credit Summary
  – Load eSchedules With and Without Losses
  – EDC Hourly Loss De-ration Factors
  – EDC Inadvertent Allocations
  – Inadvertent Interchange Charge Summary
  – Meter Correction Charge Summary
  – Meter Correction Allocation Charge Summary

Replace current point-to-point loss charge/credit reports
• **Modified PJM Settlement Reports**
  – Monthly LMP Postings (DA, RT, and FTR Zonal)
  – Daily Real-time Energy Transactions
  – Spot Market Energy Summary
  – Congestion Summary
  – Explicit Congestion Charges
  – FTR Target Allocations
  – Load Response Monthly Summary
  – Energy Congestion Losses Charges Reconciliation
    (was formerly just Energy Reconciliation)
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-Out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
<table>
<thead>
<tr>
<th>Application</th>
<th>Changes</th>
</tr>
</thead>
<tbody>
<tr>
<td>eData</td>
<td>Posting Components of the LMP eDataFeed</td>
</tr>
<tr>
<td>eMKT</td>
<td>Posting Components of the LMP Change to Demand Bidding strategy. MINOR CHANGE TO MUI</td>
</tr>
<tr>
<td>eSchedule</td>
<td>EDC Load Carve-Out process impacts New/Modified Reports</td>
</tr>
<tr>
<td>eMTR</td>
<td>Load De-Ration procedure added and additional data displayed Meter Correction Charge reports moved to eSchedules</td>
</tr>
<tr>
<td>eFTR</td>
<td>Congestion Price will be used in the settlement calculation NO CHANGE to MUI</td>
</tr>
<tr>
<td>Load Response</td>
<td>Loss Value Definition NO CHANGE TO MUI</td>
</tr>
<tr>
<td>eCapacity</td>
<td>No Application Changes</td>
</tr>
<tr>
<td>EES</td>
<td>No Application Changes</td>
</tr>
<tr>
<td>eDART</td>
<td>No Application Changes</td>
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<tr>
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• Provide means to display the marginal loss information by component
• eDataFeed will include means to query PJM for marginal loss information (loss component of price)
• Include the marginal loss effect into the Day-Ahead formulation
• Add the posting of components of Day-Ahead LMPs to eMKT
  – Total LMP, Loss Price, Congestion Price
• Modifications to XML queries to download all three LMP components.
### Total LMP, Loss Price, Congestion Price

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### Footnotes:
- **LMP**: Locational Marginal Price
- **Loss Price**: Price for losses
- **Congestion Price**: Price for congestion

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No screen changes!
Demand bids should NOT reflect losses!
• Load Responsibility “load plus losses” data submitted in accordance with PJM eSchedules deadlines
  – “Lossless” load values will be determined by PJM using hourly EDC loss de-ration factors
  – EDCs may “carve-out” entire load to others same as today
  – eSchedule deadline changes being discussed by Market Settlements Working Group
• New report showing Load Responsibility eSchedule data with and without losses (under Interchange category)
• New report showing all EDCs’ hourly loss de-ration factors (under Modeling Data)
• Other new and modified reports
• Create new procedure to calculate and store de-rated loss adjustment

• Add de-rated loss adjustment, load data (with and without losses), and applicable EDC loss de-ration factor to Load Submission screen

• Add EDC de-rated loss adjustment to Daily Meter Value Allocation screen
• Tie and generator meter data submitted in accordance with PJM eMTR deadlines
  – eMTR deadline changes being discussed by Market Settlements Working Group
• eMTR displays include the following additional hourly data available each day after the deadline:
  – PJM Mid-Atlantic EDC shares of 500 kV losses
  – EDC total “load with losses” values
  – EDC “de-rated loss adjustment” values
  – EDC total “load without losses” values
  – Hourly EDC “loss de-ration factors” (based on state-estimated losses)
eMTR Changes

eMTR Allocation Screen (for EDCs)

If the date selected is after the Marginal Losses implementation date, the Allocated Inadvertent row is replaced by De-rated Loss Adjustment.

After 6/1/07
eMTR Load Submission Screen (for EDCs)

Calculated Load changes to Load with Losses and, if the date selected is after the Marginal Losses implementation date, De-rated Loss Adjustment, Load without Losses, and EDC Loss De-rating Factor are also shown.

After 6/1/07
• No changes to the user interface
• Congestion price will be used in settlements calculation for FTR Target Allocation
• Losses are not hedged by FTRs
Load Response

- No changes to the user interface
- Credits for day-ahead and real-time demand reductions
  - PJM will de-rate reduction (previously grossed up for losses) based on EDC Loss De-ration Factor
  - Credit based on “Lossless load”
- Charges allocated by zonal load ratio shares
  - Based on “Lossless load”
• No changes to the user interface
• Up-to congestion transactions continue to clear on the delta of total LMP
  – These look like “Up-to total price differences” transactions
Application Changes - Summary

- No major changes to application user interfaces
- LMP component breakdown will be available via eDATA, eDATAfeed and eMKT (Day-ahead)
- New and revised Market Settlement reports available via eSchedules
- Minor eMTR changes to show loss de-ration
- Day-ahead Demand Bids should not include losses following Marginal Loss implementation
• Transmission Losses Definition
• Marginal Loss Calculation
• Loss Surplus Allocation
• Business Examples
• Load Carve-Out Process Changes
• Settlements Changes
• PJM Application Changes
• Next Steps
Combined Training Approach

- Documentation (i.e., Manuals, FAQs, and User Guides) will be ready and become available for review concurrent to the training schedule.
- Stakeholder review of the manuals at the PC, MIC, MRC, is expected to begin in February/March, 2007.
- Schedule Market Settlements Working Group Meetings in April & May, 2007 as readiness in addition to training sessions.
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