PJM/MISO Cost Allocation For Economic Upgrades

Stakeholder Meeting
Midwest ISO, Carmel, IN

June 16, 2008

Topics for Discussion

• Internal RTO Economic Processes	(RTO Staffs)
• MISO/PJM Straw Proposal	(RTO Staffs)
• Review Stakeholder Proposals	(All)
• Stakeholder Discussion	(All)
• Next Steps	(All)

Internal PJM Economic Process

Annual Benefit Metric

Annual Benefit = (.7)(∆System Production Cost)+(.3)(∆Load Energy Payment)

- **∆System Production Cost** is change in system generation variable cost (fuel costs, variable O&M costs and emissions costs) associated with total PJM energy production
- **∆Load Energy Payment** is change in net load energy payment (change in gross load payment minus change in transmission right credit)
  - For projects that have costs allocated regionally (500 kV and up), the load energy payment for all PJM zones is considered
  - For projects that have costs allocated using a flow-based methodology (below 500 kV) , the load energy payment for only those PJM zones that show a decrease in load energy payment is considered

Process Overview (cont.)

Simulation/Model Details

- Annual market simulations made with and without upgrade for future years 1, 4, 7 and 10 (current year (cy), cy+3, cy+6 and cy+9)
- Annual benefits within the 10-year time frame for years which were not simulated interpolated using these simulation results
- Annual benefits for years beyond the 10-year simulation time frame based on an extrapolation of the market simulation results for years 1, 4, 7 and 10
- A higher-level annual market simulation made for future year 15 (cy+14) to validate the extrapolation results and extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly

Cost/Benefit Analysis

- Present value of annual project benefit for first 15 years of project life compared to present value of annual project cost for first 15 years of project life
- Project is considered economic and included in RTEP if B/C ratio exceeds 1.25:1

Example of Benefit Calculation for Single Year

Zone	Delta Gross Load Payment ($Millions)	Delta FTR Credit ($Millions)	Delta Net Load Payment ($Millions)
ACEC	**-15.4**	-0.5	**-14.9**
AEP	224.4	99.0	125.4
APS	42.7	-429.9	472.6
BG&E	**-217.7**	-36.7	**-180.9**
COED	146.4	-3.4	149.8
DOM	**-555.6**	-372.6	**-183.0**
DP&L	27.5	-6.5	33.9
DPLC	**-30.2**	-3.8	**-26.4**
DQE	59.1	21.2	37.9
JC	**-23.6**	-7.7	**-15.9**
ME	**-22.8**	-16.4	**-6.4**
PECO	**-52.6**	2.3	**-54.8**
PEPCO	**-256.2**	-16.5	**-239.7**
PN	39.2	-9.3	48.4
PPL	**-38.2**	-26.7	**-11.5**
PSEG	**-46.7**	-1.7	**-45.0**
RECO	**-1.3**	0.0	**-1.3**
Neptune	**-5.0**	0.0	**-4.9**
Total	**-726.0**	**-809.4**	**83.4**
	Sum of Neg Values = **-1,265.2**		Sum of Neg Values = **-784.7**

Delta System Production Cost = -$153.3 M
Delta Gross Generator Revenue = $83.4 M
Delta System Congestion Costs = -$809.4 M

Annual Benefit Metric Calculation

Benefit = (.7)($153.3M) + (.3)(-83.4) **= $82.3M**
(for 500 kV and above)

Benefit = (.7)($153.3M) + (.3)($784,7) **= $342.7M**
(for below 500 kV)

Annual Benefit / Annual Costs

Year	Calendar Year	Annual Production Cost Savings ($M)	Annual Net Load Payment Savings ($M)	Annual 70%/30% Benefit ($M)	Annual Cost ($M)
1*	**2007**	**153.3**	**-83.4**	**82.3**	200
2	2008	149.1	-111.9	70.8	200
3	2009	144.9	-140.3	59.3	200
4*	**2010**	**140.8**	**-168.8**	**47.9**	200
5	2011	165.1	-68.5	95.0	200
6	2012	189.4	31.8	142.1	200
7*	**2013**	**213.7**	**132.2**	**189.2**	200
8	2014	230.6	314.0	255.7	200
9	2015	247.6	495.9	322.1	200
10*	**2016**	**264.6**	**677.8**	**388.6**	200
11	2017	267.7	613.3	371.3	200
12	2018	281.2	699.4	406.7	200
13	2019	294.8	785.6	442.0	200
14	2020	308.4	871.7	477.4	200
15	2021	321.9	957.9	512.7	200
16	2022	335.5	1,044.1	548.1	200
17	2023	349.0	1,130.2	583.4	200
18	2024	362.6	1,216.4	618.7	200
19	2025	376.2	1,302.5	654.1	200

*** Simulation Year**

C/B analysis uses 15 years of project costs and benefits starting with project in-service year

NPV Analysis

- Present value of annual project benefit for first 15 years of project life compared to present value of annual project cost for first 15 years of project life
- Project is considered economic and included in RTEP if B/C ratio exceeds 1.25:1

15 year NPV benefit	1,731.12
Project NPV cost	($1,039.01)
15 Year Net Benefit	**$692.11**

B/C Ratio = 1,731 / 1,039 = 1.66 > 1.25

pjm

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Internal MISO Economic Process

- Benefit Metric is calculated on region level (MISO East, Central and West Region).
- For each hour, calculate the region's Load Cost Saving, and region's Adjusted Production Cost Saving.
  - Region's Load Cost Saving: is the change in load energy payment (Load * Load LMP)
  - Region's Adjusted Production Cost Saving: is the change of Region's Adjusted Production Cost, which equals:

    Region's Production Cost (fuel costs, variable O&M costs and emissions costs)

    + Region's Purchase * Region Load Weighted LMP (if it purchase at that hour)

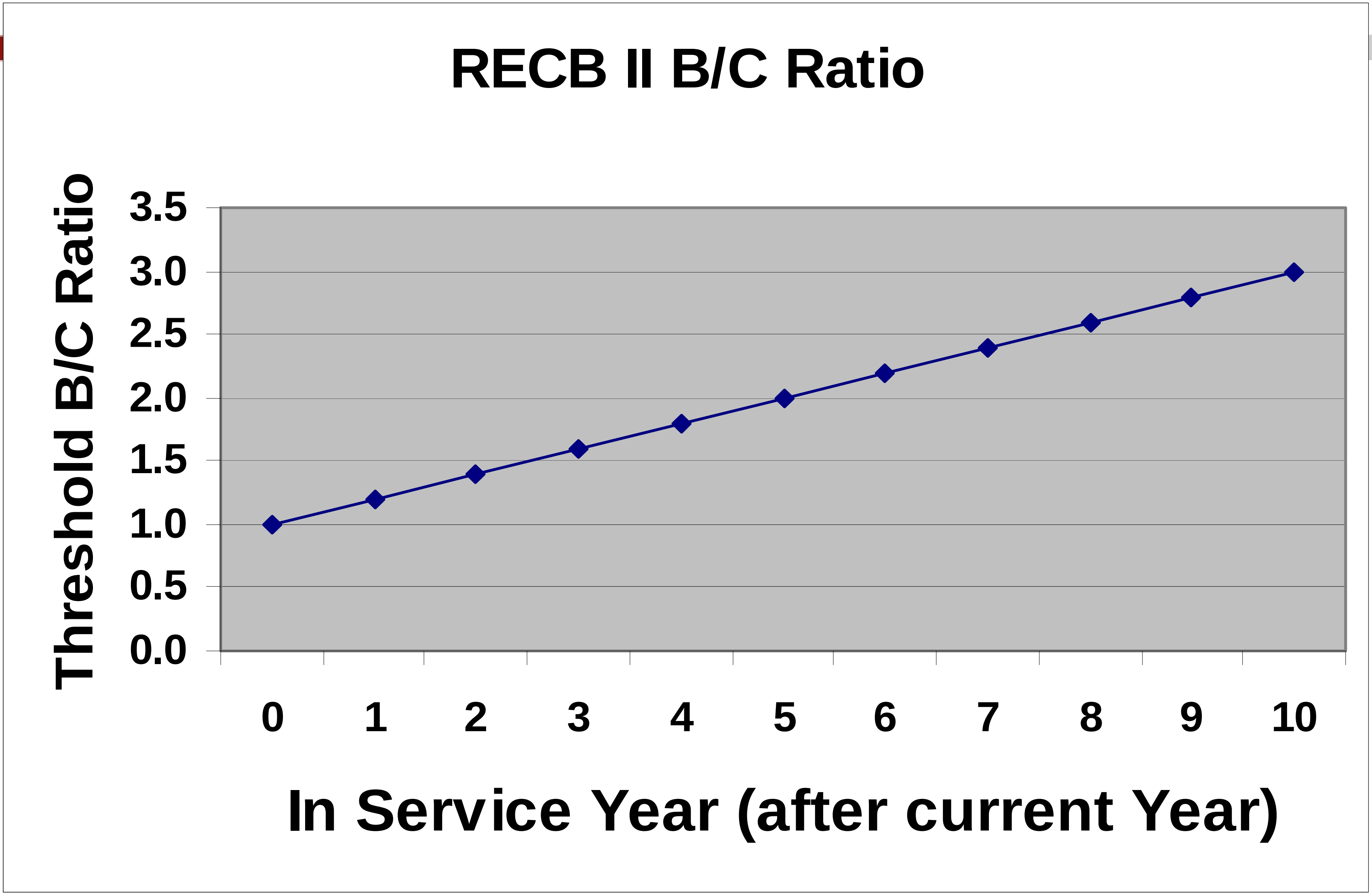
    - Region's Sale * Region Generation Weighted LMP (if it sales at that hour)
- Region's Annual Benefit = 70% * Region's Annual Adjusted Production Cost Saving + 30% * Region's Annual Load Cost Saving

Study Year

- MISO Tariff Language:
  "minimum of 10 years of benefits with a maximum 20 year horizon model"
- For a project with ISD of 2011, we will run PROMOD for: the in service year (2011), 5 years after (2016) and 10 years after (2021). For the years between, these 3 years, we will use the linear interpolation based 3 years values.

Benefit/Cost Ratio

- Present value of MISO's annual benefit (sum of regions') for the first 11 years (2011 to 2021 if ISD is 2011) of project life compared to present value of annual project cost for first 11 years of project life
- The threshold B/C ration increases linearly with the time until planned in-service date.


RECB II B/C Ratio
Threshold B/C Ratio
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0
1
2
3
4
5
6
7
8
9
10
In Service Year (after current Year)

Cost Allocation

- Twenty percent (20%) of the Project Cost of the Regionally Beneficial Project shall be allocated on a system-wide basis to all Transmission Customers and recovered through a system-wide rate.
- Eighty percent (80%) of the costs of the Regionally Beneficial Projects shall be allocated on a sub rgion-wide basis to all Transmission Customers in each of the three defined Planning Sub Regions. The region with negative total NPV benefit will not share any portion of these 80% cost.
  - Example 1:
    Total NPV Benefit: East: M$100; Central: M$200, West: M$300
    Then Cost Allocation: East: 16.67%, Central: 33.33%, West: 50%
  - Example 2:
    Total NPV Benefit: East: M$-100; Central: M$200, West: M$300
    Then Cost Allocation: East: 0%, Central: 40%, West: 60%

Current Year:	2008				
Project Cost:	70,362,500	In Service Year:	2011		
Annual RR:	14%	Discount Rate:	10%	Inflation Rat	3%
B/C Ration Threshold:	1.6				

	Cost		Original Benefit (Positive is Saving)								
			West			Center			East		
	Annual Cost		APC	LMP	WGNL	APC	LMP	WGNL	APC	LMP	WGNL
2011	$10,764,180	Simulated Value	(306,165)	(14,449,057)	(4,549,033)	361,196	382,424	367,565	7,348	1,731,228	524,512
2012	$10,764,180		3,118,739	(9,429,755)	(645,809)	(388,682)	2,829,411	576,746	132,115	4,723,582	1,509,555
2013	$10,764,180	Interpolated Values	6,543,644	(4,410,453)	3,257,415	(1,138,560)	5,276,398	785,927	256,883	7,715,936	2,494,599
2014	$10,764,180		9,968,549	608,849	7,160,639	(1,888,438)	7,723,385	995,109	381,650	10,708,290	3,479,642
2015	$10,764,180		13,393,453	5,628,151	11,063,863	(2,638,316)	10,170,371	1,204,290	506,418	13,700,645	4,464,686
2016	$10,764,180	Simulated Value	16,818,358	10,647,453	14,967,086	(3,388,195)	12,617,358	1,413,471	631,185	16,692,999	5,449,729
2017	$10,764,180		37,572,174	38,648,446	37,895,055	(4,420,282)	1,277,042	(2,711,085)	778,232	3,607,566	1,627,032
2018	$10,764,180	Interpolated Values	58,325,989	66,649,440	60,823,024	(5,452,370)	(10,063,273)	(6,835,641)	925,278	(9,477,867)	(2,195,665)
2019	$10,764,180		79,079,805	94,650,433	83,750,993	(6,484,458)	(21,403,589)	(10,960,197)	1,072,325	(22,563,299)	(6,018,363)
2020	$10,764,180		99,833,620	122,651,427	106,678,962	(7,516,545)	(32,743,905)	(15,084,753)	1,219,371	(35,648,732)	(9,841,060)
2021	$10,764,180	Simulated Value	120,587,436	150,652,421	129,606,931	(8,548,633)	(44,084,221)	(19,209,309)	1,366,417	(48,734,165)	(13,663,757)

		NPV Cost	NPV Benefit (Postive is Saving)								
			West			Center			East		
NPV Discount Rate		Annual Cost	APC	LMP	WGNL	APC	LMP	WGNL	APC	LMP	WGNL
1	2011	$10,764,180	(306,165)	(14,449,057)	(4,549,033)	361,196	382,424	367,565	7,348	1,731,228	524,512
0.909090909	2012	$9,785,619	2,835,218	(8,572,504)	(587,099)	(353,347)	2,572,192	524,314	120,105	4,294,166	1,372,323
0.826446281	2013	$8,896,017	5,407,970	(3,645,003)	2,692,078	(940,959)	4,360,659	649,527	212,300	6,376,807	2,061,652
0.751314801	2014	$8,087,288	7,489,518	457,437	5,379,894	(1,418,812)	5,802,693	747,640	286,740	8,045,297	2,614,307
0.683013455	2015	$7,352,080	9,147,909	3,844,103	7,556,767	(1,802,006)	6,946,501	822,546	345,890	9,357,725	3,049,441
0.620921323	2016	$6,683,709	10,442,877	6,611,230	9,293,383	(2,103,802)	7,834,387	877,654	391,916	10,365,039	3,383,853
0.56447393	2017	$6,076,099	21,208,512	21,816,040	21,390,771	(2,495,134)	720,857	(1,530,337)	439,292	2,036,377	918,417
0.513158118	2018	$5,523,727	29,930,455	34,201,701	31,211,829	(2,797,928)	(5,164,050)	(3,507,765)	474,814	(4,863,644)	(1,126,723)
0.46650738	2019	$5,021,570	36,891,313	44,155,126	39,070,456	(3,025,047)	(9,984,932)	(5,113,013)	500,247	(10,525,946)	(2,807,611)
0.424097618	2020	$4,565,063	42,339,201	52,016,178	45,242,294	(3,187,749)	(13,886,612)	(6,397,408)	517,132	(15,118,542)	(4,173,570)
0.385543289	2021	$4,150,058	46,491,677	58,083,030	49,969,083	(3,295,868)	(16,996,376)	(7,406,020)	526,813	(18,789,130)	(5,267,970)
Total NPV		$76,905,410	211,878,484	194,518,281	206,670,423	(21,059,455)	(17,412,258)	(19,965,296)	3,822,597	(7,090,624)	548,631

NPV of aggregated APC: 194,641,625

NPV of aggregated LMP: 170,015,399

187,253,757 FERC WANTS ELIGIBILITY BASED ON 70/30 WEIGHTED BENEFIT - WHICH IS THE SAME AS THE TOTAL WGNL BENEFIT IF THE WGNL IS NOT SET TO ZERO ANNUALLY, BUT ALWAYS SET TO THE WEIGHTED VALUE, WHICH THEY ALSO WANT

NPV of aggregated WGNL: 187,253,757

		B/C Threshold	
B/C Ratio	2.43	1.6	**Larger than Threshold, Do The Porject**

Cost Sharing

Region	NPV of WGNL	Allocation Share
West	$ 206,670,423	100%
Central	$ (19,965,296)	0%
East	$ 548,631	0%
Total NPV	$207,219,053	

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MISO/PJM Economic Planning Process
Straw Proposal

- Differences in the internal processes of PJM and Midwest ISO
- Proposals to merge areas of difference into a common cross-border approach
- Straw proposal
- Issues needing further discussion to reach common ground

Benefit metric
- PJM uses 70% Prod Cost + 30% Net LMP_{load}
- MISO uses 70% Adj. Prod Cost + 30% Gross LMP_{load}

Benefit to cost ratio threshold
- PJM: 1.25
- MISO: linear function of in-service date (2.0 for 5 year, 3.0 for 10 year)

Qualifying project voltage
- PJM: voltages 100 kV and above
- MISO: voltages 345 kV and above

Qualifying project (or allocated) cost ("materiality")
- PJM internal:
- MISO internal: $5 M Project Direct Cost Estimate
- Cross border Reliability: $10 M minimum allocated

Years studied for benefit determination
- PJM: future years 1, 4, 7, 10; Interpolation for interim years; Extrapolation beyond year 10
- MISO: In-service date year (ISD), ISD + 5, ISD + 10; Interpolation for interim; max 20 year horizon

Allocation
- PJM: 500 kV and above regionalized by load ratio share; below 500 kV ?
- MISO: 20% regionalized load ratio share; 80% using Benefit Metric to each of 3 Sub-regions (W, C, E)

Proposed Resolution of Process Differences

Benefit metric

- Use 70% Adj. Prod Cost + 30% Net LMP_{load}
- Adj. PC would be evaluated for the aggregate super-region
- Adjustment would account for any changes in economic purchases or sales between the super-region and the outside world, to the extent modeled (modeling assumptions yet to be addressed fully)
- Net LMP_{load} estimated using reduction in aggregate super-region LMP_{Gen}

Benefit to cost ratio threshold

- Use: 1.25
- Lower B/C ratio appropriate together with using LMP_{load} net of transmission rights

Qualifying project voltage

- Use: voltages 100 kV and above

Qualifying project (or allocated) cost ("materiality")

- Use: $20 M Project Direct Cost Estimate

Years studied for benefit determination

- Use: In-service date year (ISD), ISD + 5, ISD + 10; Interpolation for interim years; Extrapolation to year 15

Principles

- Allocation method does not necessarily need to be based on same metric used to determine project value/benefit
- A cross border project should show sufficient value to each RTO to be treated as cross border, otherwise develop using internal processes/tariffs
- Benefits to each RTO should be evident for each simulated year to improve stakeholder confidence in project benefits
- Project should pass a super-region cost/benefit test, as well as, internal RTO cost-benefit tests

1. Project must pass super-region benefit/cost test
   - PV of a single region-wide benefit metric must exceed PV of total project cost by pre-defined threshold

2. Project must show sufficient, consistent benefits to both RTOs
   - Measure benefit to both RTOs and determine if measures are consistent and significant for both RTOs
   - allocate costs based on this measure

3. Project must pass internal RTO benefit/cost test
   - Use existing internal RTO metrics and RTO costs from step 2 to determine if project passes internal RTO benefit/cost test

- Measure change in total system production cost (weighted 70%) plus change in total system net load payment (weighted 30%) where total system is the combined MISO + PJM systems
  - Adjust production cost for any changes in economic purchases or sales between the super-region and the outside world, to the extent modeled
  - Net load payment change estimated using change in gross generator revenue
- Compare PV of 15 years of benefits to PV of 15 years of total project costs
- Project passes super-region B/C test if B/C ratio greater than 1.25

- Measure change in zonal gross load payments and determine each RTOs share of the total load payment decreases of benefiting zones
- If each RTOs share of the total load payment decreases of benefiting zones is consistent and significant then allocate project cost based on each RTOs share
  - Each RTOs share of the total gross load payment savings for zones showing a decrease in gross load payment considered to be consistent and significant if at least 20% of the total for each simulated year

- From the simulations made to determine super-region benefit, pull the data needed to calculate annual benefit metrics used in individual RTO test
  - Adjusted production cost and gross load payment for MISO
  - Production cost and net load payment for PJM
- Apply internal RTO test to costs allocated to RTO in Step 2
- Project must pass both internal RTO tests in order to be recommended as a cross-border economic project

Straw Proposal Example
Annual Simulation Results

RTO	Zone	Delta Gross Gen Rev ($Millions)	Delta Prod Cost ($Millions)	Estimated Delta Adjusted PC ($Millions)	Delta Gross Load Payment ($Millions)	Delta FTR Credit ($Millions)	Delta Net Load Payment ($Millions)
MISO	Zone 1	-13.4	-7.1	-8.8	-15.4	-0.5	-14.9
MISO	Zone 2	359.6	104.6	-42.2	224.4	99.0	125.4
MISO	Zone 3	506.8	120.3	-23.2	42.7	-429.9	472.6
MISO	Zone 4	-211.4	-41.4	-52.4	-217.7	-36.7	-180.9
MISO	Zone 5	190.2	44.9	-13.7	146.4	-3.4	149.8
MISO	Zone 6	36.7	11.2	7.0	27.5	-6.5	33.9
MISO	Zone 7	-230.6	-73.5	-113.2	-256.2	-16.5	-239.7
MISO	SUBTOTAL	**637.9**	**159.0**	**-246.6**	**-48.3**	**-394.5**	**346.2**
PJM	Zone 1	-467.4	-233.2	-168.1	-555.6	-372.6	-183.0
PJM	Zone 2	-36.7	-21.2	-15.8	-30.2	-3.8	-26.4
PJM	Zone 3	84.2	8.9	-24.8	59.1	21.2	37.9
PJM	Zone 4	-7.8	2.3	-12.2	-23.6	-7.7	-15.9
PJM	Zone 5	-29.9	-10.3	-0.8	-22.8	-16.4	-6.4
PJM	Zone 6	-112.1	-34.0	8.7	-52.6	2.3	-54.8
PJM	Zone 7	129.4	6.2	-78.3	39.2	-9.3	48.4
PJM	Zone 8	-43.5	-11.9	8.2	-38.2	-26.7	-11.5
PJM	Zone 9	-70.8	-19.0	-3.7	-46.7	-1.7	-45.0
PJM	Zone 10	0.0	0.0	-6.3	-6.3	-0.1	-6.2
PJM	SUBTOTAL	**-554.5**	**-312.3**	**-292.9**	**-677.7**	**-414.9**	**-262.8**
	TOTAL	**83.4**	**-153.3**	**-539.5**	**-726.0**	**-809.4**	**83.4**

Super-region Straw Parameters

Annual Simulation Results

RTO	Delta Net Load Payment ($Millions)	Delta Prod Cost ($Millions)
Combined	83.4	-153.3

Benefit Metric = (.7)(Delta Prod Cost) + (.3)(Delta Net Load Payment[1])

= (.7)($153.3M) + (.3)(-$83.4M) = $82.3M

(1) On a total system basis, Delta Gross Gen Rev can be used in place of Delta Net Load Payment under assumption that all congestion charges are rebated back to load via transmission rights credits

Straw Proposal Example
(1) Super-region Benefit/Cost Test (cont.)

Year	Annual Production Cost Savings ($M)	Annual Net Load Payment Savings ($M)	Annual 70%/30% Benefit ($M)	Annual Cost ($M)
1	153.3	-83.4	82.3	200
2	149.1	-111.9	70.8	200
3	144.9	-140.3	59.3	200
4	140.8	-168.8	47.9	200
5	165.1	-68.5	95.0	200
6	189.4	31.8	142.1	200
7	213.7	132.2	189.2	200
8	230.6	314.0	255.7	200
9	247.6	495.9	322.1	200
10	264.6	677.8	388.6	200
11	267.7	613.3	371.3	200
12	281.2	699.4	406.7	200
13	294.8	785.6	442.0	200
14	308.4	871.7	477.4	200
15	321.9	957.9	512.7	200

Compare PV of 15 years of total system benefit to 15 years of total system costs

Project passes super-region benefit/cost test if B/C ratio > 1.25

Straw Proposal Example
(2) Determine Mutual Benefits and Allocate Costs

RTO	Zone	Delta Gross Load Payment ($Millions)
MISO	Zone 1	-15.4
MISO	Zone 2	224.4
MISO	Zone 3	42.7
MISO	Zone 4	-217.7
MISO	Zone 5	146.4
MISO	Zone 6	27.5
MISO	Zone 7	-256.2
MISO	SUBTOTAL	**-48.3**
PJM	Zone 1	-555.6
PJM	Zone 2	-30.2
PJM	Zone 3	59.1
PJM	Zone 4	-23.6
PJM	Zone 5	-22.8
PJM	Zone 6	-52.6
PJM	Zone 7	39.2
PJM	Zone 8	-38.2
PJM	Zone 9	-46.7
PJM	Zone 10	-6.3
PJM	SUBTOTAL	**-677.7**
	TOTAL	**-726.0**

Delta Gross Load Payment ($Millions)	
-15.4	1.2%
-217.7	17.2%
-256.2	20.2%
-489.3	**38.7%**
-555.6	43.9%
-30.2	2.4%
-23.6	1.9%
-22.8	1.8%
-52.6	4.2%
-38.2	3.0%
-46.7	3.7%
-6.3	0.5%
-775.9	**61.3%**
-1,265.2	**100.0%**

Use RTO share of the total gross load payment savings for zones showing a decrease as measurement of consistent, mutually beneficial results

Allocate project cost based on RTO share of the total gross load payment savings for zones showing a decrease

MISO receives 38.7% of project cost and PJM receives 61.3% cost and these costs are tested against internal RTO B/C test

Straw Proposal Example
(3) Individual RTO Benefit/Cost Test

RTO	Zone	Delta Gross Gen Rev ($Millions)	Delta Prod Cost ($Millions)	Estimated Delta Adjusted PC ($Millions)	Delta Gross Load Payment ($Millions)	Delta FTR Credit ($Millions)	Delta Net Load Payment ($Millions)
MISO	Zone 1	-13.4	-7.1	-8.8	-15.4	-0.5	-14.9
MISO	Zone 2	359.6	104.6	-42.2	224.4	99.0	125.4
MISO	Zone 3	506.8	120.3	-23.2	42.7	-429.9	472.6
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MISO	SUBTOTAL	**637.9**	**159.0**	**-246.6**	**-48.3**	**-394.5**	**346.2**
PJM	Zone 1	-467.4	-233.2	-168.1	-555.6	-372.6	-183.0
PJM	Zone 2	-36.7	-21.2	-15.8	-30.2	-3.8	-26.4
PJM	Zone 3	84.2	8.9	-24.8	59.1	21.2	37.9
PJM	Zone 4	-7.8	2.3	-12.2	-23.6	-7.7	-15.9
PJM	Zone 5	-29.9	-10.3	-0.8	-22.8	-16.4	-6.4
PJM	Zone 6	-112.1	-34.0	8.7	-52.6	2.3	-54.8
PJM	Zone 7	129.4	6.2	-78.3	39.2	-9.3	48.4
PJM	Zone 8	-43.5	-11.9	8.2	-38.2	-26.7	-11.5
PJM	Zone 9	-70.8	-19.0	-3.7	-46.7	-1.7	-45.0
PJM	Zone 10	0.0	0.0	-6.3	-6.3	-0.1	-6.2
PJM	SUBTOTAL	**-554.5**	**-312.3**	**-292.9**	**-677.7**	**-414.9**	**-262.8**
	TOTAL	**83.4**	**-153.3**	**-539.5**	**-726.0**	**-809.4**	**83.4**

Internal PJM Parameters

Internal MISO Parameters

(3) Individual RTO Benefit/Cost Test (cont.)

MISO Internal RTO B/C Test

- Benefit = (.7)($246.6M) + (.3)($48.3M) = $187.1M
- Compare to 38.7% of project cost

PJM Internal RTO B/C Test

- Benefit = (.7)($312.3M) + (.3)($262.8M) = $297.5M
- Compare to 61.3% of project cost

- Project must pass both internal RTO tests in order to be recommended as a cross-border economic project
- Cost allocated within RTO based on internal RTO process

Next Steps

- Stakeholder feedback on ability to reach consensus in time for August 1, 2008 FERC filing