

EE590

Transmission Planning Projects and Cost Allocation



Ming Ni
Economic Studies, Midwest ISO

Transmission Planning Projects

■ Reliability Projects:

Identified either in the periodically performed Baseline Reliability Study, or in Facilities Studies associated with the request processes for new transmission access.

- Baseline Reliability Projects: Network upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable reliability standards.
- Transmission Access Projects
 - Generation Interconnection Projects
 - Transmission Delivery Service Projects

Transmission Planning Projects

- **Economic Project (Regionally Beneficial Projects)**

Bring economic benefits to the region. Need to pass the Benefit/Cost test.

Why Cost Sharing

- FERC Order 890 issued in early 2007
- Require compliance with nine principles
 - Coordination
 - Openness
 - Transparency
 - Information Exchange
 - Comparability
 - Dispute Resolution
 - Regional Participation
 - Economic Planning Studies, and
 - **Cost Allocation**

MISO Reliability Project Cost Allocation (RECB I)

RECB I Principles

- Load growth driven projects in one zone (utility) can benefit users in another
- Lower voltage projects have more localized benefits than higher voltage - especially within a large geographic area RTO
- Higher voltage projects have at least some effect on all grid users – but large geographic area of RTO must be considered
- New generator driven transmission projects are in-part caused by the generator, but in-part benefit more than just the generator or his customer
- New transmission for specified transmission service use (point to point requests) can be targeted to the requesting customer

BRP Project Cost Allocation

- BRP: Allocation mechanism:
 - 345 kV and above:
 - 20% of cost Postage Stamped across footprint
 - 80% allocated to specific zones based on relative impact of project on zones
 - Measure of impact is sum of Line Outage Distribution Factor (LODF)*Line Length on all other lines (branches) in MTEP model
 - Below 345 kV and above 100 kV:
 - 100% allocated to specific zones based on relative impact of project on zones
 - Measure of impact is sum of Line Outage Distribution Factor (LODF)*Line Length on all other lines (branches) in MTEP model

TAP Project Cost Allocation

- Generator Interconnection Projects
 - 50% allocated to Interconnection Customer
 - 50% allocated to zones by same mechanism as BRP
- Point-to-point Transmission Service Projects are directly assigned to requesting customer

MISO Economic Project Identification and Cost Allocation (RECB II)

Qualifying Tests

- Project Cost > \$5 million
- And project voltage is ≥ 345 kV
- And the project is not exclusively a Baseline Reliability Project or a New Transmission Access Project
- If a project is both a BRP and a RBP, allocated as RBP

Benefit Metric

- 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

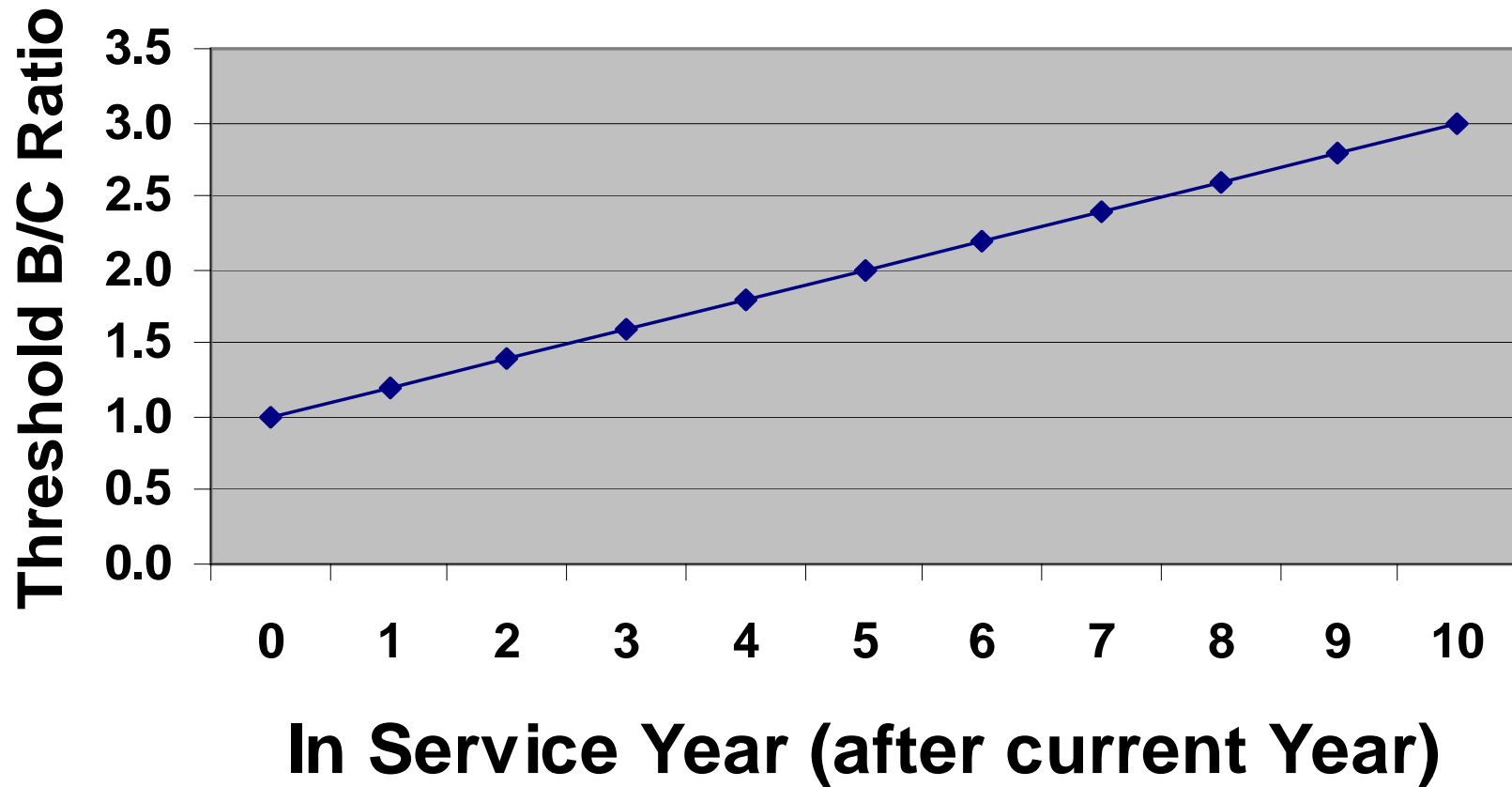
Study Year

- 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



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 region-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
 Annual RR: 14%
 B/C Ratio Threshold: 1.6

In Service Year: 2011
 Discount Rate: 10%
 Inflation Rate: 3%

Cost			Original Benefit (Positive is Saving)								
Year	Annual Cost		APC	West LMP	WGNL	APC	Center LMP	WGNL	APC	East 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	Interpolated Values	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		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	Simulated Value	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		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 (Positive is Saving)								
NPV Discount Rate	Year	Annual Cost	APC	West LMP	WGNL	APC	Center LMP	WGNL	APC	East 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
 NPV of aggregated WGNL: 187,253,757

187,253,757
 FERRE 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

B/C Ratio: 2.43
 B/C Threshold: 1.6
 Larger than Threshold, Do The Project

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	

PJM Reliability Project Cost Allocation

Cost Allocation Method

- For projects ≥ 500 kV:
 - 100% of project cost is regionally allocated to PJM zones based on load-ratio share
- For projects < 500 kV:
 - Use the DFAX (Distribution Factor) Method

Basic Concepts

■ DFAX:

DFAX = (After-shift power flow – pre-shift power flow) / Total amount of power shifted

Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area

Pre-shift power flow = Megawatt flow over the constrained transmission element before the incremental megawatt transfer

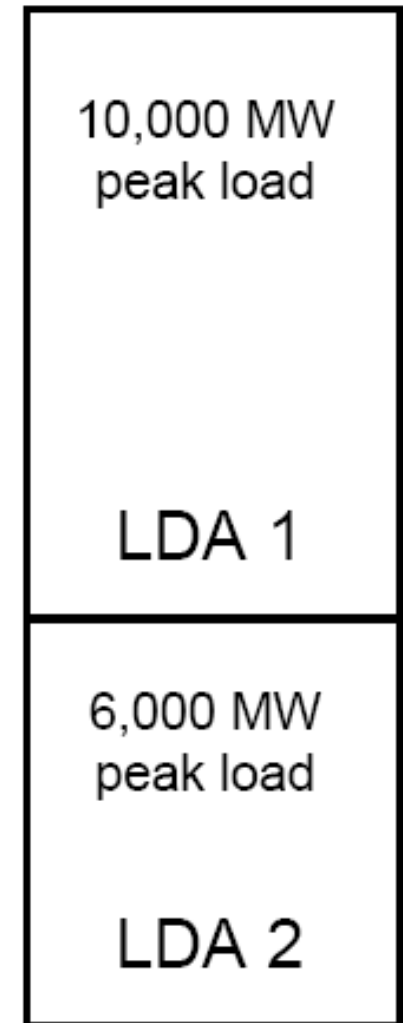
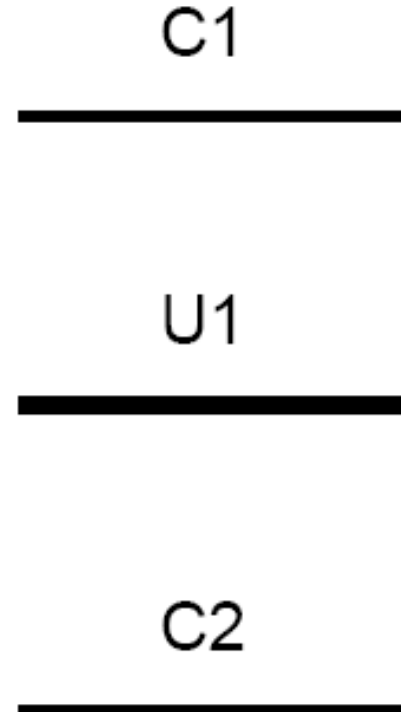
After-shift power flow = Megawatt flow over the constrained transmission element after the incremental megawatt transfer

■ Capacity Emergency Transfer Objective (“CETO”):

Transfer limitation into the LDA.

Example

- 2 LDAs
 - LDA 1 has a peak load of 10,000 MW
 - LDA 2 has a peak load of 6,000 MW
- 2 Constraints Under Contingency Conditions
 - C1 has an emergency rating of 1,000 MW
 - C2 has an emergency rating of 800 MW
- 1 Upgrade (U1) Resolves Both Criteria Violations

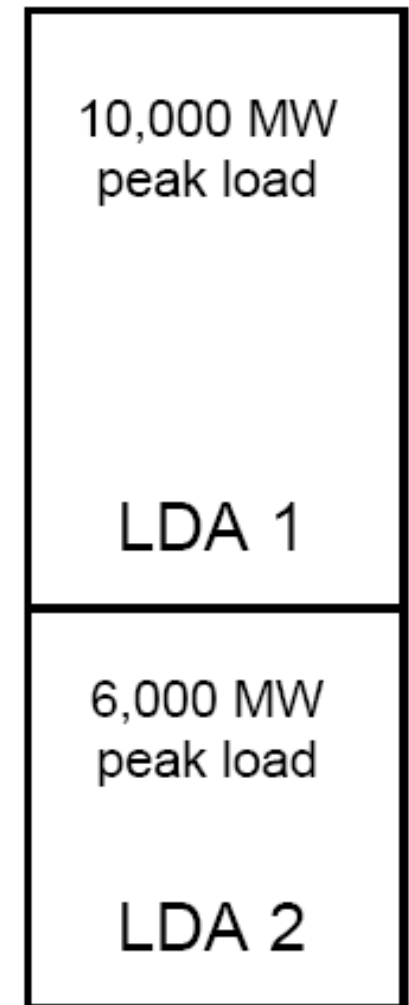


Example (Cont')

- 2 Criteria Violations
 - For the first criteria violation, C1 has a post-contingency flow of 1,200 MW
 - For the second criteria violation, C2 has a post-contingency flow of 850 MW

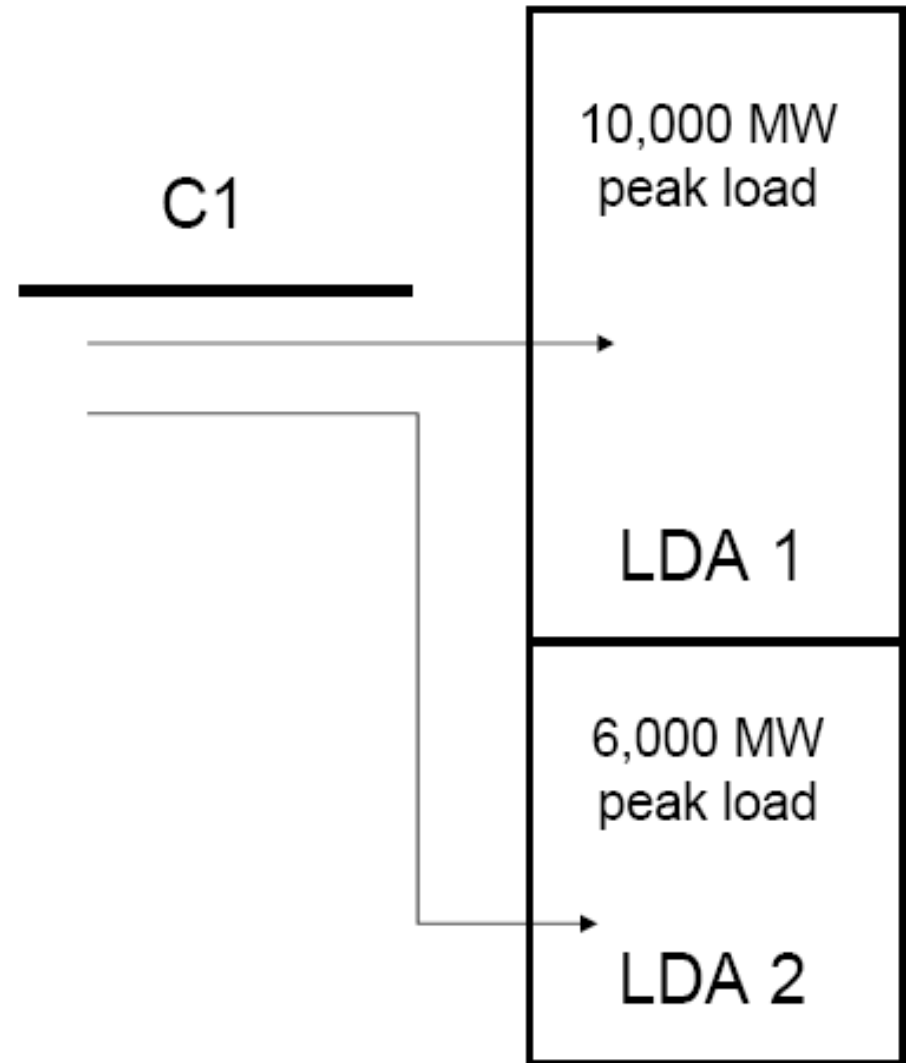
C1
—————
→
1,200 MW
(200 MW overload)

C2
—————
→
850 MW
(50 MW overload)



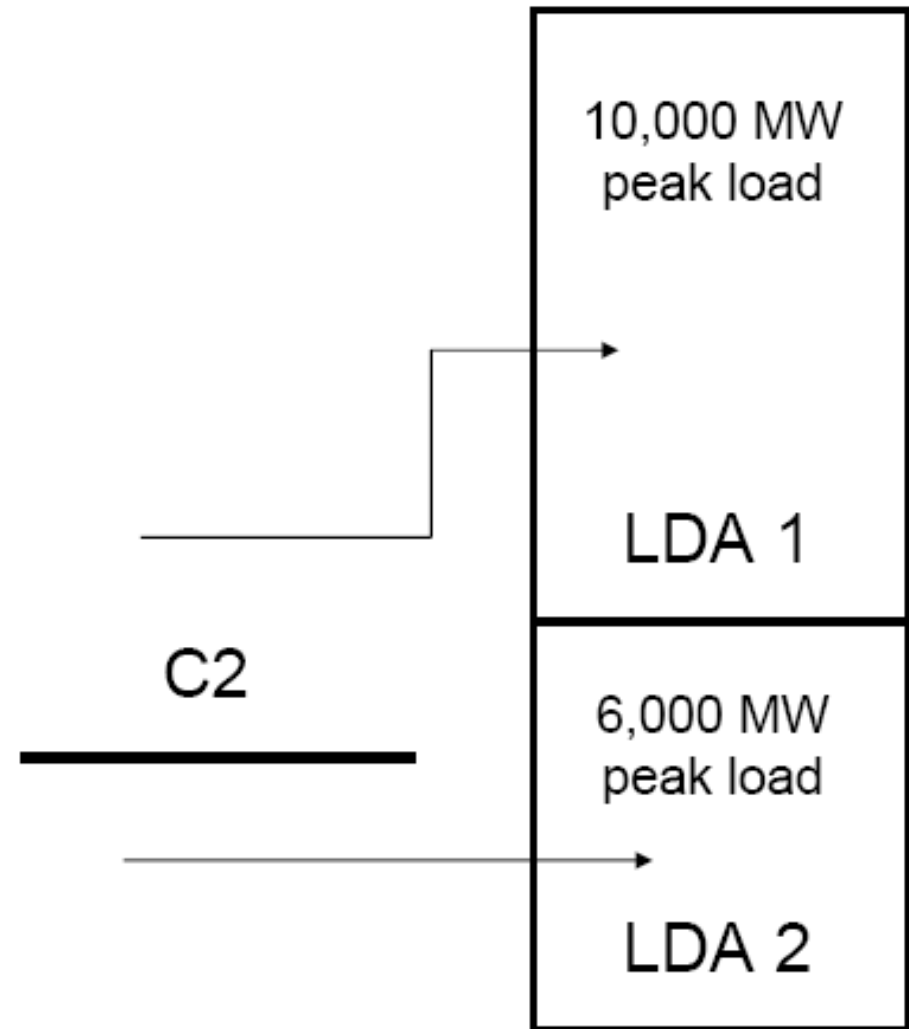
Example (Cont')

- DFAX
 - LDA 1 has a 10% DFAX on constrained facility C1
 - LDA 2 has a 5% DFAX on constrained facility C1



Example (Cont')

- DFAX
 - LDA 1 has a 5% DFAX on constrained facility C2
 - LDA 2 has a 20% DFAX on constrained facility C2



Example (Cont')

		LDA 1	LDA 2	Total
1 Peak Load	From RTEP Data	10,000	6,000	
2 Constraint C1				
3 DFAX	From DFAX Analysis	0.10	0.05	
4 MW Impact	Line 1 * Line 3	1000	300	1300
5 Overload on C1	From RTEP Analysis			200
6 Contribution to Overload on C1	Line 5 Total * (Line 4 / Line 4 Total)	153.8	46.2	200
7 Constraint C2				
8 DFAX	From DFAX Analysis	0.05	0.20	
9 MW Impact	Line 1 * Line 8	500	1200	1700
10 Overload on C2	From RTEP Analysis			50
11 Contribution to Overload on C2	Line 10 Total * (Line 9 / Line 9 Total)	14.7	35.3	50
12 Total of MW Overloads	Line 5 + Line 10			250
13 Total of MW Contributions to Overloads	Line 6 + Line 11	168.6	81.4	250
14 Allocation	Line 13 / Line 12 Total	0.67	0.33	

PJM Economic Project Identification and Cost Allocation

Process Overview

Annual Benefit Metric

$$\text{Annual Benefit} = (.7)(\Delta\text{System Production Cost}) + (.3)(\Delta\text{Load Energy Payment})$$

- **$\Delta\text{System Production Cost}$** is change in system generation variable cost (fuel costs, variable O&M costs and emissions costs) associated with total PJM energy production

- **$\Delta\text{Load Energy Payment}$** 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

Process Overview (cont.)

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)

Example of Benefit Calculation for Single Year (cont.)

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
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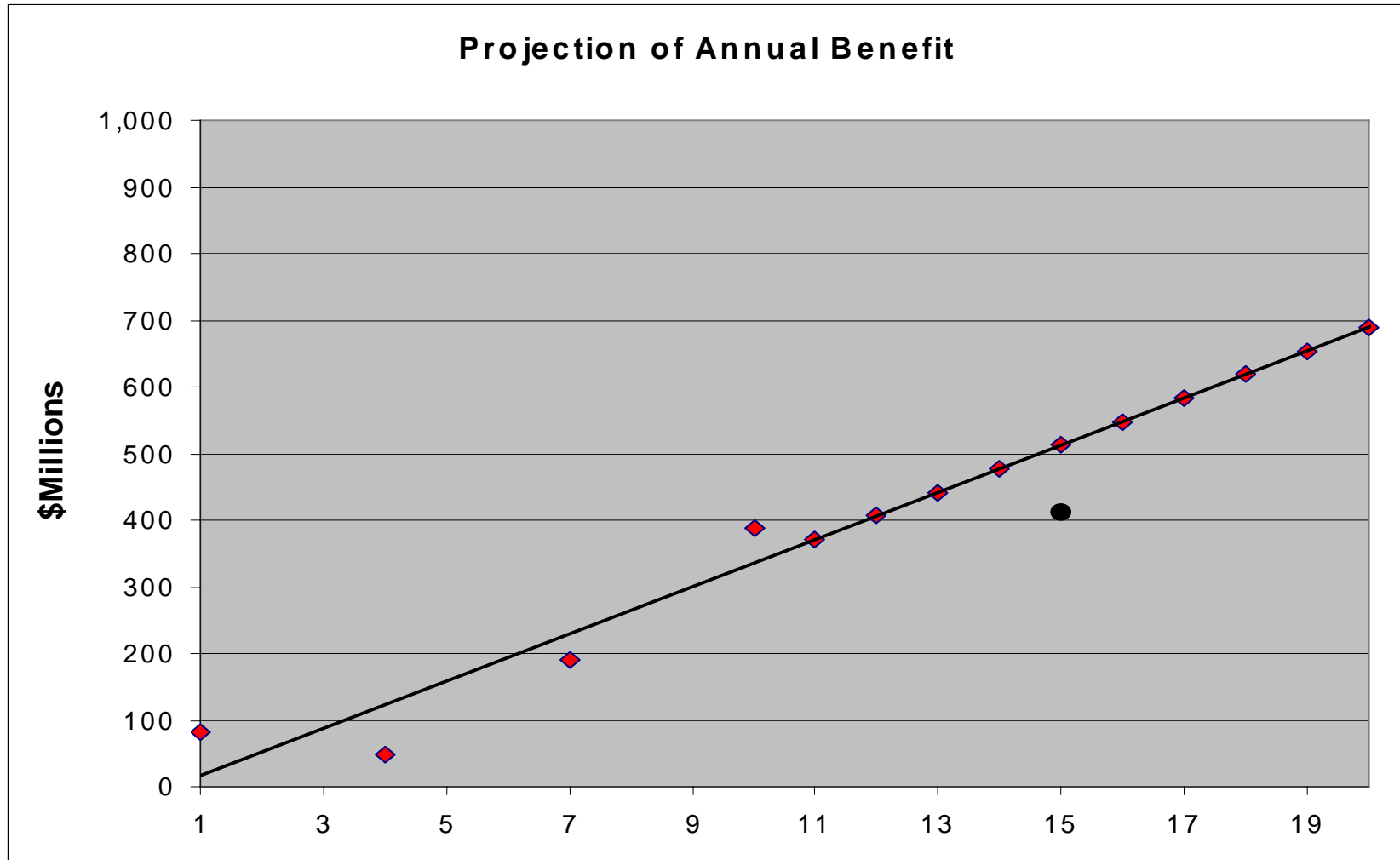
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Sum of Neg Values = -784.7

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

Note: On a total system basis, Delta Net Load Payment = Delta Gross Gen Revenue and Delta Congestion Costs = Delta FTR Credits therefore explicit calculation of FTR credits is not necessary in order to determine Delta Net Load Payments for entire system.

Annual Benefit Extrapolation



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

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

* Simulation 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

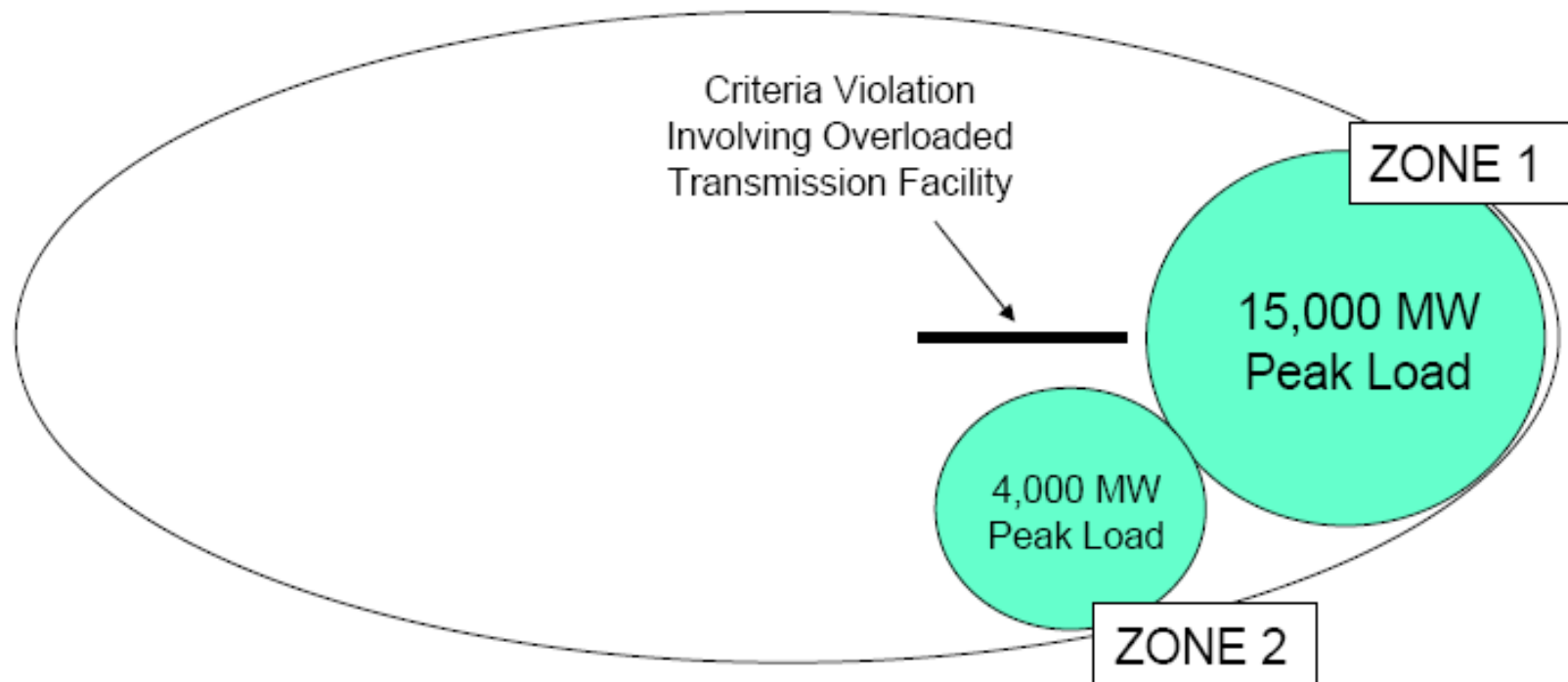
15 year NPV benefit	1,731.12
Project NPV cost	(\$1,039.01)
15 Year Net Benefit	\$692.11

$$\text{B/C Ratio} = 1,731 / 1,039 = 1.66 > 1.25$$

Cost Allocation Method

- For projects ≥ 500 kV:
 - 100% of project cost is regionally allocated to PJM zones based on load-ratio share
- For projects < 500 kV:
 - Use the DFAX (Distribution Factor) Method

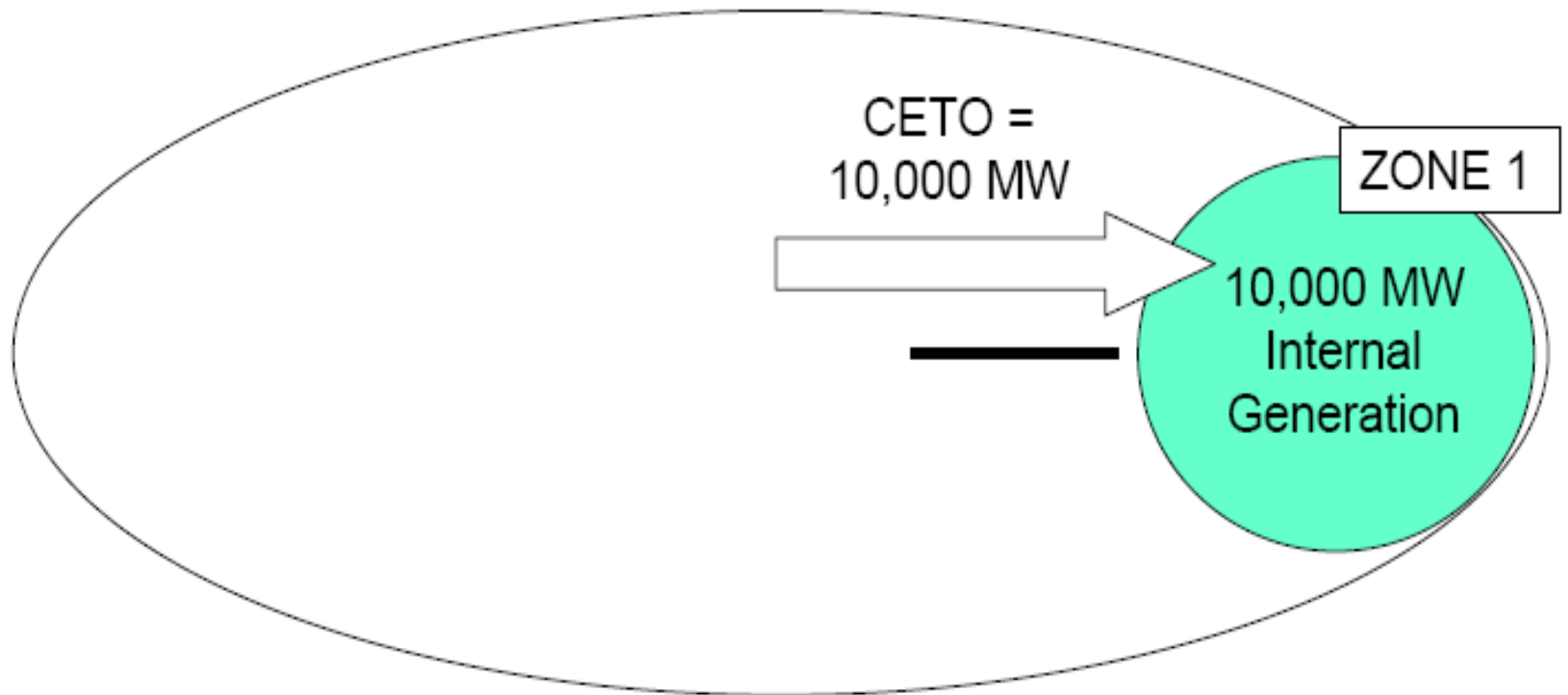
Cost Allocation Example



ZONE 1 has a peak load of 15,000 MW

ZONE 2 has a peak load of 4,000 MW

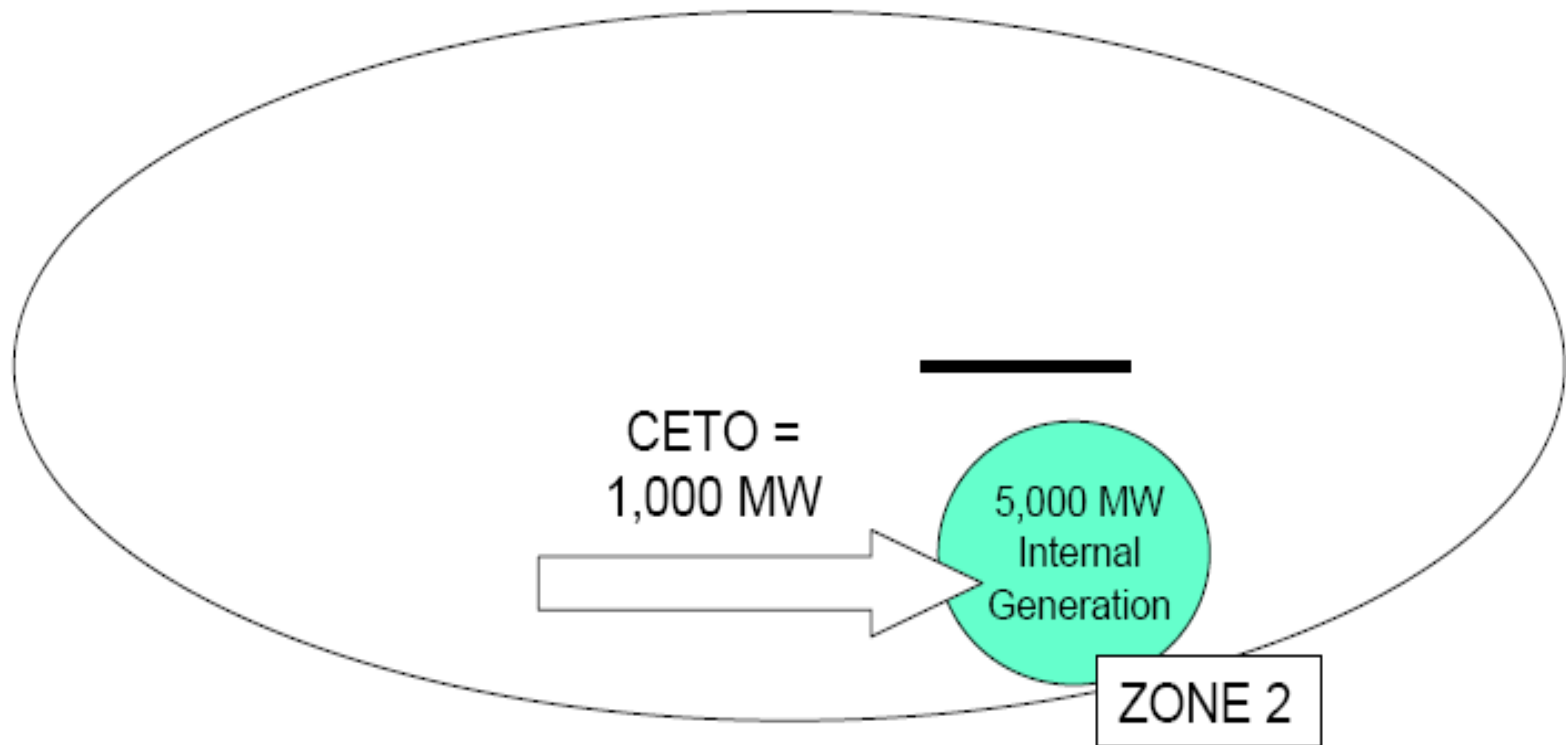
Cost Allocation Example (Cont')



ZONE 1 has 10,000 MW of generation

ZONE 1 has a CETO of 10,000 MW

Cost Allocation Example (Cont')



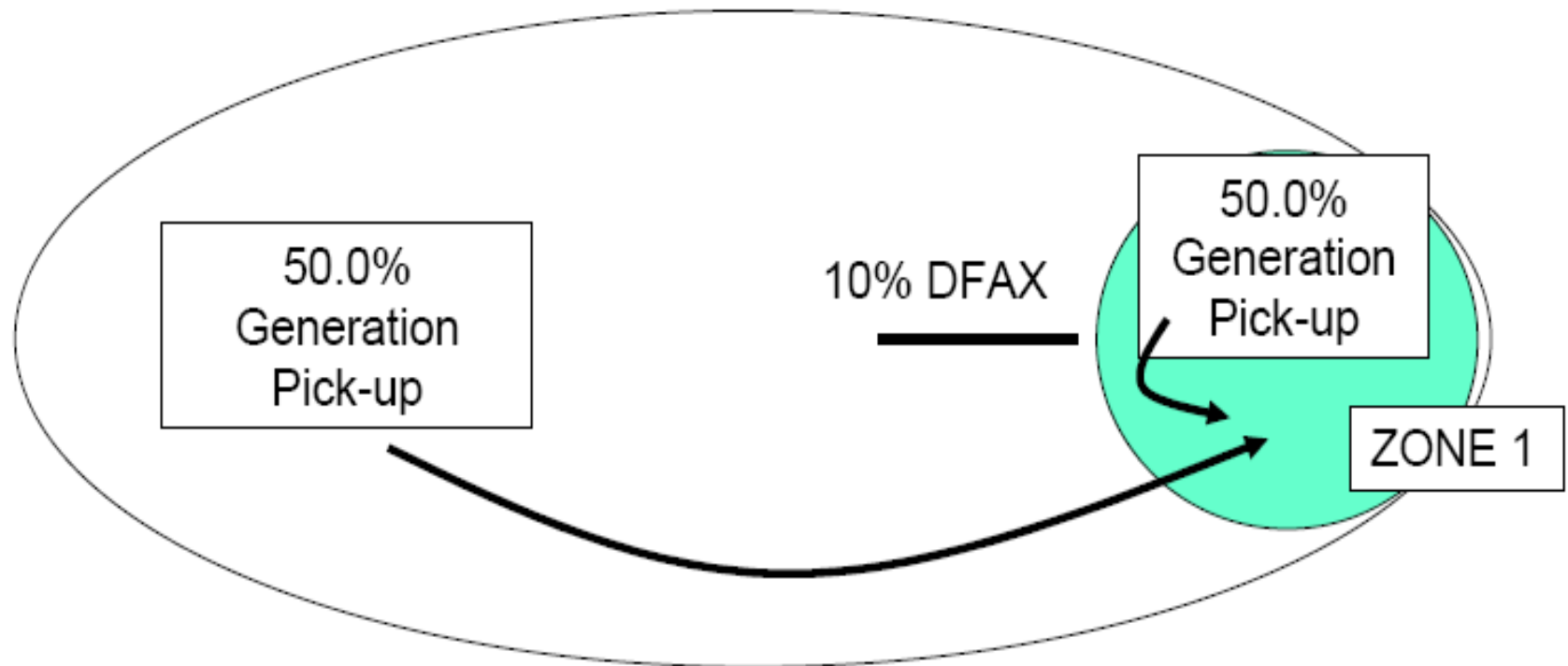
ZONE 2 has 5,000 MW of generation

ZONE 2 has a CETO of 1,000 MW

Cost Allocation Example (Cont')

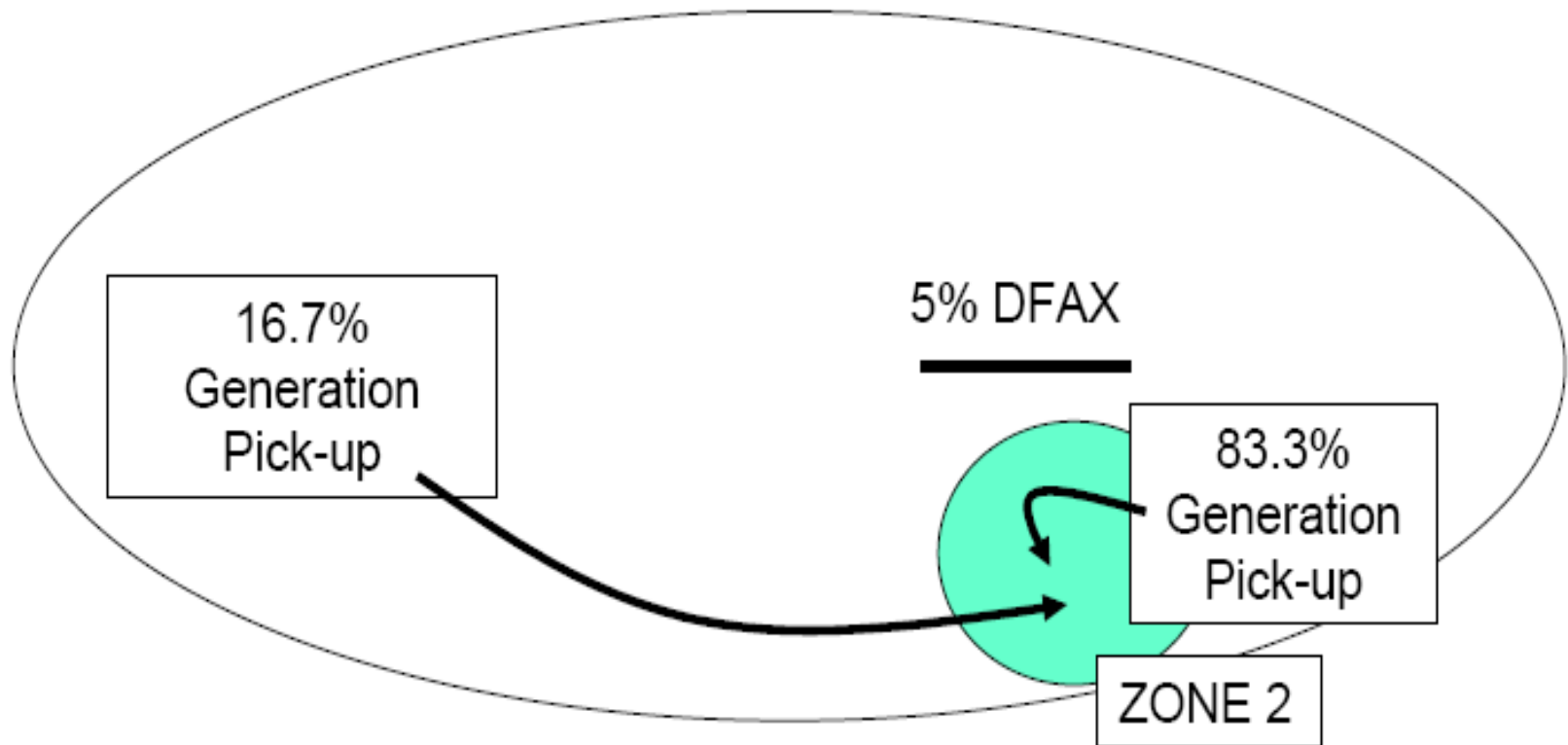
	INTERNAL GENERATION (a)	CETO (b)	INTERNAL ZONE GENERATION PARTICIPATION FACTOR (a) / [(a) + (b)]	NON-ZONE GENERATION PARTICIPATION FACTOR (b) / [(a) + (b)]
ZONE 1	10,000 MW	10,000 MW	50.0%	50.0%
ZONE 2	5,000 MW	1,000 MW	83.3%	16.7%

Cost Allocation Example (Cont')



DFAX calculated using production power flow software
Source is 50% within ZONE 1 and 50% in rest of RTO
Sink is ZONE 1 load

Cost Allocation Example (Cont')



DFAX calculated using production power flow software
Source is 83.3% within ZONE 2 and 16.7% in rest of RTO
Sink is ZONE 2 load

Cost Allocation Example (Cont')

	PEAK LOAD	DFAX	MW IMPACT	ALLOCATION
ZONE 1	15,000 MW	0.10	1,500 MW	88.24%
ZONE 2	4,000 MW	0.05	200 MW	11.76%