Cost Allocation for the Midwest ISO

ATRR Whac-a-Mole?

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Cost allocation of transmission investment costs continues to be a major obstacle to building large new transmission and achieving renewables generation goals in the Midwest ISO (MISO) region. Existing methods of cost allocation can result in disproportionate impacts on certain utilities in close proximity to new transmission, so new methods of cost allocation are being proposed. Like the carnival game of Whac-a-Mole, any particular cost allocation method that eases the annual transmission revenue requirement (ATRR) on some MISO regions or utilities will inevitably burden other MISO regions or utilities.

Unintended Consequences

Prior to October of 2009, the MISO tariff called for the investment costs of major baseline reliability projects in the Midwest ISO Transmission Expansion Plan (MTEP) with a voltage of 100 kV to 344 kV to be allocated to the local pricing zones where the transmission was built and nearby zones impacted by the new transmission capacity. This allocation method used a formula based on line outage distribution factor (LODF). Under the LODF method, the power flow effects (and the cost) of new transmission are typically greatest in the pricing zone where the new transmission facilities will be located and tend to diminish with distance from that zone. For eligible projects that were 345 kV and above, 80% of the costs of the project were allocated based on LODF and 20% of the costs were socialized to all MISO transmission customers.

By contrast, the cost of a transmission project that was needed to connect a new generator, such as a new wind, gas or coal project, was funded 100% up front by the generator and paid to the transmission owner with 50% of the cost refunded back from the transmission owner (TO) over time in the form of rate credits. The generator was eligible for the rate credit if the project was a network resource and/or the generator secured at least a one-year contract with a MISO network customer. For the 50% refunded portion, the formula followed the same LODF approach as the baseline reliability projects above (i.e., 80% recovered from the local pricing zone and 20% of the refunded amount recovered from customers in all pricing zones for projects 345 kV and above and 100% recovered locally for projects less than 345 kV). Notably, however, the American Transmission Company, International Transmission, Michigan Electric Transmission and ITC Midwest provide 100% reimbursement of transmission costs for new generators rather than 50% in order to encourage new generation and/or the expansion of their transmission rate base.

With the proliferation of state renewables standards and the vast wind potential in the upper Midwest, the MISO queue for requests from wind generators to build transmission to interconnect to the grid has skyrocketed. Transmission owners, such as Otter Tail Power and Montana Dakota Utilities (MDU), have requests from wind generators in their pricing zone that are several times higher than the amount of load in their zones, thus concluding that the benefits of wind generation must be going to other pricing zones within MISO or other non-MISO regions. In its July 9, 2009 filing with FERC (Docket ER09-1431), the Midwest ISO estimated that the interconnection queue as of July, 2009 had 12,150 MW of requests in the Otter Tail and MDU pricing zones, yet these two pricing zones combined had less than 1,350 MW of load. The LODF method for allocating costs had the unintended consequence of burdening those utilities with large service territories but sparse population (e.g., Otter Tail and MDU) with higher transmission rates as the result of the proliferation of wind generation in these wind-rich areas.

Tourniquet to Stop the Bleeding

Based on the LODF method of cost allocation described above, Otter Tail and MDU faced large transmission rate increases to their native load due to the disproportionate amount of proposed generators in their zone. Otter Tail and MDU threatened to withdraw from the Midwest ISO (each gave their one-year notice) unless the tariff was dramatically changed. In an attempt to keep Otter Tail, MDU and possibly others in MISO (there are six zones in which pending generator interconnections exceed the load in the zone) and prevent an unraveling of MISO, the Midwest ISO presented FERC in July, 2009 with an “immediate correction” proposal that called for the elimination of LODF and the reassignment of those costs to the generator rather than the local pricing zone(s).

Effectively, that meant for projects under 345 kV, the generator would pay100% of the costs, and for projects 345 kV and above, the generator would pay 90% of the costs with the remaining 10% spread across the entire MISO footprint. This interim solution, named “Phase I,” would give MISO and stakeholders some breathing room to develop a better solution by July, 2010. The interim solution, however, was viewed by wind generators as unfair and a policy that would discourage renewable investment. After listening to all stakeholders, FERC ruled in October, 2009 that the 90-10 interim method for allocating transmission costs was a reasonable stopgap measure, but directed the MISO and the MISO TOs to develop and file by July 15, 2010 superseding tariff revisions addressing generator interconnection and cost allocation within MISO. FERC was empathetic to the challenges involved with cost allocation:

> *We recognize that cost allocation is one of the most difficult and contentious issues facing the Midwest ISO region at this time.*

The Regional Expansion Criteria Benefits (RECB) Task Force of stakeholders is pursuing a permanent solution to the MISO cost allocation issue by July 15, 2010 (“the RECB Phase II process”). The solution for Phase II is to solve/improve the generator interconnection issue coming out of RECB Phase I, but also to provide an acceptable cost allocation method to transmission owners that are investing on their own in major projects or as part of consortiums to integrate large quantities of remote generation. The FERC Order states:

> *Filing Parties state that the Phase II stakeholder process will focus on the integration of location-constrained resources and will include a new category of cost sharing for transmission projects driven primarily by the need to integrate large quantities of remote*

generation resources. Filing Parties explain that "Phase II involves a comprehensive look at transmission upgrade cost allocation in light of possible major 'superhighway' transmission projects to facilitate regional or inter-regional movement of large quantities of power from remote areas." In addition, Filing Parties indicate that Phase II includes a consideration of additional improvements to the Phase I revisions to the generator interconnection project cost allocation methodology. Furthermore, Filing Parties propose to provide the Commission with reports on the status of the Phase II stakeholder process thirty days after the end of each calendar quarter and state that the first report would be submitted on approximately October 30, 2009.

FERC ruled in favor of MISO's interim solution:

As we explained in Order No. 2003, independent system operators, like Midwest ISO, have significant discretion to propose an appropriate cost allocation methodology for interconnection-related network upgrades, including providing interconnection customers with capacity rights made feasible by such projects. In Order No. 2003, the Commission stated "[f]or a Transmission Provider that is an independent entity, such as an RTO or ISO, we allow flexibility as to the specifics of the interconnection pricing policy.

FERC goes on to state that Phase II should look at alternative cost allocation approaches:

Also, Filing Parties' proposal is only an interim approach and we fully expect that all methodologies, including those used by SPP and CAISO, will be evaluated in the Phase II stakeholder process.

To emphasize the need to look at alternatives to the 90-10 interim solution, the Commission went on to say in its October, 2009 Order:

… cost allocation proposals for interconnection-related upgrades should pay attention to cost-causation principles and to identifying the full array of benefits to generators, load, and other entities in the region from enhanced transmission infrastructure.

Some of the criteria or principles that have been mentioned by various stakeholders used to determine the new method of cost allocation include:

1. Ensure more interconnection-related upgrade costs are allocated to the parties that cause, or benefit from, such costs. That is, charge both the new generation and the load for access.
2. Minimize free riders by allocating the costs of "lumpy" transmission upgrades to all present and future beneficiaries of those upgrades.
3. Increase the proportion of costs to load that are causing the increases in renewables generation (often remote from the generation).
4. Send appropriate signals to generators to efficiently locate their plants on the grid.
5. Reflect changes in system usage of transmission, generation and load over time.

The Initial Answer: Injection-Withdrawal Cost Allocation

In the fourth quarter of 2009 and the first few months of 2010, the RECB Task Force evaluated the use of the injection-withdrawal (I/W) method of cost allocation within MISO. Under the pure I/W cost allocation method, both the generator (the injector) and the user (the withdrawer) pay for use of the transmission system. Costs for injection-withdrawal are both fixed (based on MW) and variable (based on MWh usage). The local generation and the load for a pricing zone is subject to a local, fixed monthly access charge, but only the load is subject to the variable MWh usage charge.

All indications were that I/W (or some form of it) would be the solution. In its November, 2009 progress update to FERC, the Task Force stated, "The RECB Task Force will continue evaluating the Injection-Withdrawal model in concert with the Organization of MISO States (OMS) and the Cost Allocation and Regional Planning (CARP) group." The OMS is comprised of representatives from state commissions that have utilities in MISO. For new eligible projects, the injection-withdrawal method would replace the current network rate schedule. I/W would apply to and replace the existing cost allocation processes, including RECB Phase I, which covers baseline reliability and generator interconnection projects, and RECB Phase II, which covers regionally beneficial projects. Interestingly, MISO's I/W method covered eligible baseline reliability, economic and "superhighway" projects.

Two Layers of Costs for Projects Eligible for Injection-Withdrawal

The injection-withdrawal method, as originally proposed by MISO and outlined in March 2010 (as discussed later, MISO later amended this proposal), allocates the revenue requirement of a transmission owner's new transmission investment in MTEP's Appendix A to two major layers of costs or rates, the regional layer and the local layer (see Exhibit 1). The regional layer applies to the entire MISO footprint and is based on a usage charge ($ per MWh); the local layer is based on an access charge ($ per MW).

Initially, MISO considered three layers: local, sub-regional (West, Central and East planning regions) and regional (entire MISO footprint) instead of only two layers. After evaluating the pros and cons with stakeholders, the RECB Task Force and MISO eliminated the sub-regional layer. This third layer was eliminated largely in the name of simplicity and is similar to the two-layer scheme of SPP's proposed highway/byway method. The two-layer method is a hybrid between pure injection-withdrawal and highway/byway. One MISO analysis early in the stakeholder process showed that eliminating the sub-regional layer transferred, on average, about 68% of the costs to the regional layer (entire MISO footprint) and about 32% of the costs to the local layer. The movements varied by MISO sub-region and voltage level.

Exhibit 1

Injection-Withdrawal Method of Cost Recovery

Rate/Cost Layer	Geography	Billing Determinant / Comments
Regional usage rate	Entire MISO footprint	Usage Charge • $/MWh consumed by load (withdrawals) • $/MWh of export and wheel through transactions out of MISO
Local access rate	Corresponds to existing 23 pricing zones	Access Charge for Each Pricing Zone • Installed capacity (MW) of new generators' zone (injections) plus • 12-month CP (coincident peak) demand of load coincident with the peak of the pricing zone

Exhibit 2

2024 Transmission Usage Study Allocation Factors
To be Applied to Revenue Requirements for Transmission Owners

Cost Layer	Local	Regional
Central below 345 kV	55%	45%
Central 345 kV	48%	52%
Eastern below 345 kV	64%	36%
Eastern 345 kV	59%	41%
Western below 345 kV	43%	57%
Western 345 kV	27%	73%
MISO-wide above 345 kV (applied to entire footprint)	6%	94%

This "hybrid injection withdrawal" method eliminates the sub-regional layer and tends to favor the MISO West region (i.e., a lower revenue requirement), because most of the investments in the West are large and expansive and would impact the West sub-region and the entire MISO, rather than locally. Thus by eliminating the sub-region layer, a large portion of these costs from investments in the West are shared throughout the MISO footprint, rather than largely getting allocated to only the West sub-region.

By contrast, a higher proportion of the East and Central regions' investments tend to affect the local areas. One MISO estimate from February, 2010 showed that eliminating sub-regions under injection-withdrawal moved $477 million in charges to load from the West to the Central and East Regions.[1] This significant cost shifting shows the contentious details involved with cost allocation methodologies.

Under MISO's March 22, 2010 hybrid I/W method for cost allocation, an annual transmission usage study will determine how the annual transmission revenue requirement (ATRR) of new eligible transmission investment would be allocated to the two different layers. The transmission usage study models the MISO system based on power flows and branches, categorized by sub-region and voltage level.

Developed by MISO, Exhibit 2 shows the estimated allocation of transmission facilities based on 2024 projected transmission facilities. "Superhighway" or large overlay facilities, like the proposed Green Power Express, may fall into the over-345kV category and thus, an estimated 94% of its costs will be allocated across the MISO footprint. The local access rate ($/MW) for each pricing zone and the Midwest ISO-wide regional usage rate ($/MWh) are calculated based on the local or regional allocation of the annual revenue requirements by voltage class.

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1 Midwest ISO presentation on Injection-Withdrawal to OMS CARP, February 8-9, 2010. Page 4.

2 The Fargo line is categorized as a Baseline Reliability Project in the MISO 2008 MTEP and so remains under the existing cost allocation methodology of 80-20. However, since Fargo data is readily available, it is used as an example on how changing to the I/W cost allocation methodology would impact the pricing zones.

Exhibit 3
Distribution of ATRR of Fargo Transmission Line Using 80-20 Methodology

Using the MISO LODF and the Existing 80/20 Cost Allocation Methodology

Transmission Owners		Sub Regional (80%)		Postage Stamp (20%)		Total
Ameren Illinois	$	-	$	1,538,409	$	1,538,409
Ameren Missouri	$	-	$	1,541,202	$	1,541,202
ATC System	$	32,498,596	$	2,428,000	$	34,926,596
Columbia Water & Light	$	-	$	51,333	$	51,333
City Water, Light & Power	$	-	$	76,824	$	76,824
Duke	$	-	$	2,187,400	$	2,187,400
FirstEnergy	$	-	$	2,395,525	$	2,395,525
Great River Energy	$	2,895,567	$	216,331	$	3,111,898
Hoosier Energy	$	-	$	119,776	$	119,776
Indianapolis Power & Light	$	-	$	557,152	$	557,152
ITC	$	-	$	1,954,657	$	1,954,657
ITC Midwest	$	8,787,194	$	656,499	$	9,443,694
Montana - Dakota Utilities Co.	$	1,799,505	$	134,443	$	1,933,948
Michigan Joint Zone	$	-	$	1,507,330	$	1,507,330
MidAmerican	$	-	$	787,101	$	787,101
Minnesota Power	$	5,241,935	$	391,630	$	5,633,565
Muscatine Power & Water	$	-	$	27,587	$	27,587
Northern Indiana Public Service Company	$	-	$	623,849	$	623,849
Northern States Power	$	24,952,359	$	1,864,214	$	26,816,573
Otter Tail Power	$	2,224,843	$	166,220	$	2,391,063
Southern Illinois Power Cooperatives	$	-	$	83,808	$	83,808
Southern Minnesota Municipal Power Agency	$	-	$	55,523	$	55,523
Vectren	$	-	$	235,187	$	235,187
Total	**$**	**78,400,000**	**$**	**19,600,000**	**$**	**98,000,000**

Impact on TOs of Injection-Withdrawal vs. Previous Methods of Cost Allocation

The ATRR for a baseline reliability transmission project is based on the Transmission Owner's fixed charge rate times their transmission project cost. In the following example, the CapX Twin Cities to Fargo project (345 kV) is used to illustrate the impacts of moving from the existing cost allocation method to the injection-withdrawal method using the three-layer (regional-sub regional-local) and two-layer (regional-local) methodologies.[2]

Assuming a Fargo Line project cost of $490 million and a fixed carrying charge of 20%, the ATRR for the Fargo Line would be $98 million. The existing cost allocation method (80-20) would distribute the ATRR for the Fargo Line as shown in Exhibit 3. In the existing cost allocation method, the majority of the Fargo ATRR is paid for by the seven TOs (marked by blue italics) identified by MISO's LODF study. Only 20% of the Fargo ATRR is regionalized to the entire MISO footprint.

In the injection-withdrawal method (as defined by MISO in March, 2010), MISO would identify the proportion of local versus regional cost allocation for the Fargo Line. Exhibit 4 shows a sample representation of the allocations for each region based on line voltage for both the three- and two-layer I/W cost allocation methods. These percentages were developed by MISO for the purpose of estimating how the ATRR would be allocated. Each line would have its own actual allocations based on specific analysis conducted by MISO for a particular project. For example, the Fargo Line would have its own set of percentages based on its unique branch flow engineering analysis. Costs of "superhighway" projects would be allocated 94% to the MISO footprint.

Exhibit 4
Allocation of ATRR under 3-Layer and 2-Layer Approaches

2024 transmission Usage Study Allocation Factors

3 Layer Approach

	Local	Sub Regional	Regional
Central below 345 kV	44%	26%	30%
Central 345 kV	35%	30%	35%
Eastern below 345 kV	58%	21%	21%
Eastern 345 kV	48%	26%	26%
Western below 345 kV	34%	33%	33%
Western 345 kV	**14%**	**41%**	**45%**
MISO-wide above 345 kV	4%	27%	69%

2 Layer Approach

	Local	Sub Regional	Regional
Central below 345 kV	55%	0%	45%
Central 345 kV	48%	0%	52%
Eastern below 345 kV	64%	0%	36%
Eastern 345 kV	59%	0%	41%
Western below 345 kV	43%	0%	57%
Western 345 kV	**27%**	**0%**	**73%**
MISO-wide above 345 kV	6%	0%	94%

Brewing Discontent

By applying these allocation factors to the Fargo Line ATRR, we can compare the distribution of the Fargo Line ATRR using the existing 80-20 cost allocation methodology with the two variations of I/W (see Exhibit 5). Many TOs would face large cost increases by moving to the I/W method. For example, Mid-American would be allocated ATRR of only $787K (just the regional amount) under the 80-20 method, because MISO's LODF study determined that Mid-American did not directly benefit from the Fargo line (i.e., there were no allocated local costs). Contrast the 80-20 method with the 3-layer I/W approach, where Mid-American would be affected by the higher allocation of regional costs (45% vs. 20%) and the large sub-regional allocation of 41%. So, even though Mid-American would not directly benefit from the Fargo line, they assume a substantial portion of the ATRR ($6.5 million) under the 3-layer I/W approach. And, even though the regional allocation percentage would increase from 45% to 73%, the 2-layer I/W approach ends up being much less costly to Mid-American because of the removal of the sub-regional layer. These types of glaring cost shifting caused the TOs to balk at moving to I/W as MISO had outlined.

Another important example is transmission owners that are located in the Central or East regions. For example, Ameren Illinois is located in the Central region and would wind up paying 3½ times higher in ATRR under I/W 2-layer than under the 80-20 method. Remember, these estimates are based on one transmission line (and based on average percentages), but they illustrate the difficulty in reaching agreement among the TOs. That is, if most of the new large transmission is built in the MISO West region, it raises some

Exhibit 5
Comparison of Fargo Line ATRR under Three Cost Allocation Approaches

A Comparison of the Existing and I/W Cost Allocation Methodologies

Transmission Owners	Existing Cost Allocation (80% Sub Regional & 20% Postage Stamp)	Injection/Withdrawal 3 Layer Approach	Injection/Withdrawal 2 Layer Approach	Difference in ATRR in going to 2 Layer Approach from Existing Cost Allocation	% Difference in ATRR in going to 2 Layer Approach from Existing Cost Allocation
Central					
Ameren Illinois	$ 1,538,409	$ 3,472,797	$ 5,633,649	$ 4,095,240	266.20%
Ameren Missouri	$ 1,541,202	$ 3,670,758	$ 5,954,785	$ 4,413,583	286.37%
Columbia Water & Light	$ 51,333	$ 124,432	$ 201,857	$ 150,524	293.23%
City Water, Light & Power	$ 76,824	$ 164,025	$ 266,084	$ 189,260	246.35%
Duke	$ 2,187,400	$ 5,531,589	$ 8,973,467	$ 6,786,066	310.23%
Hoosier Energy	$ 119,776	$ 288,457	$ 467,942	$ 348,165	290.68%
Indianapolis Power & Light	$ 557,152	$ 1,261,293	$ 2,046,097	$ 1,488,946	267.24%
Southern Illinois Power Cooperatives	$ 83,808	$ 175,337	$ 284,435	$ 200,627	239.39%
Vectren	$ 235,187	$ 537,322	$ 871,656	$ 636,468	270.62%
East					
FirstEnergy	$ 2,395,525	$ 5,390,189	$ 8,744,084	$ 6,348,559	265.02%
ITC	$ 1,954,657	$ 4,258,984	$ 6,909,019	$ 4,954,362	253.46%
Michigan Joint Zone	$ 1,507,330	$ 3,308,773	$ 5,367,564	$ 3,860,235	256.10%
Northern Indiana Public Svc Co.	$ 623,849	$ 1,527,126	$ 2,477,337	$ 1,853,488	297.11%
West					
ATC System	$ 34,926,596	$ 24,564,749	$ 18,863,662	$ (16,062,934)	-45.99%
Great River Energy	$ 3,111,898	$ 2,902,707	$ 2,268,935	$ (842,963)	-27.09%
ITC Midwest	$ 9,443,694	$ 6,731,950	$ 5,195,625	$ (4,248,068)	-44.98%
Montana - Dakota Utilities Co.	$ 1,933,948	$ 1,780,810	$ 1,396,501	$ (537,447)	-27.79%
MidAmerican	$ 787,101	$ 6,526,623	$ 2,550,740	$ 1,763,639	224.07%
Minnesota Power	$ 5,633,565	$ 4,315,307	$ 3,255,417	$ (2,378,148)	-42.21%
Muscatine Power & Water	$ 27,587	$ 252,907	$ 110,104	$ 82,517	299.12%
Northern States Power	$ 26,816,573	$ 18,506,431	$ 14,194,881	$ (12,621,693)	-47.07%
Otter Tail Power	$ 2,391,063	$ 2,238,509	$ 1,755,128	$ (635,935)	-26.60%
Southern MN Municipal Pwr Agency	$ 55,523	$ 468,926	$ 211,032	$ 155,509	280.08%
Total	**$ 98,000,000**	**$ 98,000,000**	**$ 98,000,000**	**$ 0**	
East	$ 6,481,360	$ 14,485,071	$ 23,498,004	$ 17,016,644	262.55%
Central	$ 6,391,092	$ 15,226,010	$ 24,699,972	$ 18,308,880	286.47%
West	$ 85,127,548	$ 68,288,919	$ 49,802,024	$ (35,325,524)	-41.50%
Total	**$ 98,000,000**	**$ 98,000,000**	**$ 98,000,000**	**$ -**	

question as to the willingness of TOs in the Central and East regions to assume the regionalized costs.

Under the 2-layer I/W method, the original seven TOs (Exhibit 5 blue italics) would realize a reduction in the Fargo Line ATRR, because more of the cost is allocated to the regional cost recovery layer (MISO-wide). In the Fargo example cited above, the I/W method would result in the Central and East regions paying an increase of $17M and $18M respectively (a total of $35M) or a combined 274% more in revenue requirements than the previous 80-20 method, where 80% of the costs of the project were allocated based on LODF and 20% of the costs were regionalized to all MISO transmission customers. Note, the total Fargo Line ATRR would not be affected by changing cost allocation methodologies: $98 million of Fargo Line ATRR would be recovered under all three methods. So in effect, the I/W method proposed by MISO simply would move the cost out of the West region and into the East and Central regions, playing ATRR Whac-a-Mole. A result of that clearly does not sit well with many TOs.

Generator Interconnection Projects

This same cost-shifting that was illustrated using a baseline reliability project, (the Fargo project), also occurs for generator interconnector projects (GIPs) when moving from the previous and current methods of 50-50 and 90-10 to the injection-withdrawal 2-layer method. Exhibit 6 looks at a GIP located in the West region and compares the percentage

Exhibit 6

Sample Calculation of Generator Interconnection Project Percentage of Costs

	Layer Cost Allocation				Regional Cost Allocation				
Cost Allocation Method	**Generator**	**Local**	**Regional**	**Total**	**Generator**	**West**	**East**	**Central**	**Total**
50/50- Previous Method	50.00%	40.00%	10.00%	100.00%	50.00%	43.26%	3.28%	3.45%	100.00%
90/10 - Current Method	90.00%	0.00%	10.00%	100.00%	90.00%	3.26%	3.28%	3.45%	100.00%
I/W 2 Layer - Future Method	*Access Charge*	27.00%	73.00%	100.00%	*Access Charge*	50.82%	23.98%	25.20%	100.00%

Exhibit 7

Sample Calculation of Generator Interconnection Project Dollar Costs

Example: GIP with a $3,000,000 ATRR	Layer Cost Allocation				Regional Cost Allocation				
Cost Allocation Method	**Generator**	**Local**	**Regional**	**Total**	**Generator**	**West**	**East**	**Central**	**Total**
50/50- Previous Method	$ 1,500,000	$ 1,200,000	$ 300,000	$ 3,000,000	$ 1,500,000	$ 1,297,884	$ 98,538	$103,578	$ 3,000,000
90/10 - Current Method	$ 2,700,000	$ -	$ 300,000	$ 3,000,000	$ 2,700,000	$ 97,884	$ 98,538	$103,578	$ 3,000,000
I/W 2 Layer - Future Method	*Access Charge*	$ 810,000	$ 2,190,000	$ 3,000,000	*Access Charge*	$ 1,524,552	$719,327	$756,122	$ 3,000,000

of the ATRR associated with a 345 kV line investment that is allocated to each region under these three cost allocation methods.

Exhibit 6 also shows that under the 2-layer I/W method, more of the ATRR related to the GIP investment is allocated outside the West region than under the previous two methods (73% vs. 10%). This 2-layer approach is consistent with views that much of the remote generation will be used to serve loads outside of the West, but can significantly raise costs in the East and Central.

For example, Exhibit 7 shows $3 million of ATRR for a GIP in the Otter Tail pricing zone that uses the previous method of allocating 50% to the generator and 50% to the transmission owner. This allocation methodology means the generator would pay $1.5 million and the customers in the West region would pay $1.297 million (43% of $3 million per Exhibit 6). The remaining $203K would be paid by customers in the East region ($99K) and the Central region ($104K). Of the $1.297 million allocated to the West region, Otter Tail customers would pay the bulk of that cost based on the LODF study, thus illustrating the "Otter Tail issue" that caused them to threaten to leave MISO.

Under the 90-10 method that is currently filed and approved at FERC for 345kV and above, the generator would pay $2.7 million, the customers in the West region would pay $98K, customers in the Central region would also pay $98K and customers in the East region would pay $104K (see Exhibit 6 for percentages). Clearly, this approach would benefit Otter Tail and would shift the vast majority of costs to the generator, thus addressing the "Otter Tail issue."

Assuming a 345 kV transmission line is necessary to connect the generator in the West region to the grid, under the 2-layer I/W approach shown in Exhibit 6, about 50.8% of the cost would stay in the West with the generator picking up a portion of the cost through an access charge and the remaining portion of the 50.8% in the West would be paid by load based on an access charge and a MWh charge. The remaining 49.2% of the cost is split about evenly (24% for the East region and 25% for the Central region) based only on an MWh charge.

Exhibit 8
Calculation of GIP Access Charge

Calculation of GIP Access Charge		
Project: Wind of the Plains GIP Located in OTP Pricing Zone		
Transmission Project Estimated ATRR: $3,500,000		
OTP Pricing Zone before GIP Project		
OTP Zone Total ATRR	$	48,100,000
OTP Zone Total MWs (12 CP Load & Installed Generation Capacity)		3,568
Access Charge or OTP Zone Embedded Cost ($/MW)	**$**	**13,481**
I/W 2 Layer Allocation Factors (per Exhibit 4)		
Western Region below 345 kV Local Allocation		43.00%
Western Region below 345 kV Regional Allocation		57.00%
Wind of the Plains Generator Interconnector Project		
Generator Interconnector Project Capacity MW		100
Total Generator Interconnector ATRR Cost	$	3,500,000
Generator Interconnector Project Cost - Local Allocation	$	1,505,000
Generator Interconnector Project Local Cost ($/MW)	**$**	**15,050**
Higher of Cost paid by Generator ($/MW)	**$**	**15,050**

The I/W method proposed by MISO in March, 2010 shows that the load benefiting from the new generator would pay more of the cost and the generator would not be burdened with 90% of the cost of the line. Although under I/W, the customers of the local transmission owner, such as Otter Tail, would be assessed fewer charges than the 50-50 method, they would still pay much more than the 90-10 method, thus the “Otter Tail issue” remains.

Although generator interconnection projects have two layers of costs (regional and local) under MISO’s March, 2010 proposal, the local rate would be more complicated than under baseline reliability projects and would be designed to prevent “free riders” of new generators. For the local access rate, generation interconnection projects would pay the highest of three monthly rates:

1. The local, embedded/historical access rate, which includes the local portion of the revenue requirement of the GIP
2. The local portion of the GIP’s revenue requirement solely attributed to GIP’s network upgrade (i.e., the monthly “higher-of” access rate)
3. The pooled higher-of rate of the GIP plus the local revenue requirement of other generator’s GIPs, who would also pay the higher-of rate

The pooled rate addresses potential free rider concerns, where subsequent generators would benefit with reduced GIP costs due to the investment made by earlier generators. The pooled rate provides a crediting mechanism to first movers to encourage them to make the initial investment.

Impact on GIPs of Injection-Withdrawal vs. Previous Methods

The I/W method of cost allocation for generation interconnection projects mitigates the rate impact on local utilities by charging the higher-of rate and spreading a portion of the costs to the MISO region via the MWh regional usage rate, with the split of revenue requirements between local and the region based on the allocation factors developed by MISO.

For example, in the Otter Tail pricing zone, an interconnection project, such as the project described in Exhibit 8, is estimated to have an ATRR of about $3.5M. Assuming allocation factors of 43% local and 57% regional for voltage under 345 kV (see Allocation Factors in Exhibit 4), then about $1.5M of the revenue requirement would be applied locally and the remaining $2M would be applied regionally. Assuming a project capacity of 100 MWs, the project local cost would be $15,050 per MW, which is higher than the Otter Tail pricing zone embedded access rate of $13,481 per MW in this example. Therefore, the generator would pay the higher-of rate to keep the access charge payers in the Otter Tail pricing zone from paying the higher cost for this generator to connect to the transmission grid.

In the local pricing zone under the previous 50-50 or existing 90-10 tariffs, new generators assume 50% or up to 90% of the interconnection-related costs; local load is burdened by the remaining costs they must pay with their local share of the allocated costs and their share of the costs allocated regionally. The I/W tariff, by contrast, would preserve the embedded rate paid by local load and would hold them harmless.

New Proposal from Transmission Owners

In late March, 2010, a group of transmission owners unveiled a new cost allocation methodology to rival the injection-withdrawal and highway/byway methods[3]—much to the dismay of the chairperson Lauren Azar of the RECB Task Force who expressed her disappointment with the TOs in the May 28, 2010 informational filing at FERC:

> *Regardless of when the TO's began their effort, they neither informed Midwest ISO or the chair of both the RECB Task Force and CARP until long after that effort had begun. Moreover, the TO's had already begun discussing their proposal with individual stakeholders without informing those that have been working hard to jointly develop a model in a transparent process. At this RECB Task Force meeting, I expressed my disappointment with both the secrecy and timing of these activities.*

The emergence of the new methodology (called the "Supporting Transmission Owners Proposal") was a response from 14 TOs reflecting a dissatisfaction with injection-withdrawal that was apparent when the RECB stakeholders voted on the various cost allocation methodologies. The Supporting Transmission Owner's Proposal of April 13, 2010 had 42.5 voting *yes* and 22 voting *no*. This method was the only one out of the six methods that had more yes than no votes. The injection-withdrawal, as proposed by MISO, had 8 *yes* and 55.5 *no* votes—a clear victory for the TO proposal.

The TO proposal called for a form of injection-withdrawal to be applied only to Unique Purpose Projects (UPP). These high voltage transmission projects (including "superhighway projects") likely would cross state lines and facilitate development of low or no carbon resources, including remote renewable resources. The TO proposal called for UPP cost to be assigned 100% to all MISO load (regionally) based on a 12-month coincident peak (CP) with 0% assigned to generation (subject to potential adjustment). The export rate would apply for load outside MISO that receives benefit from the UPP.

A UPP may, in addition to meeting a public policy goal, also address an underlying reliability need or provide economic benefits. UPPs would be evaluated just as any other project in the MTEP Planning

[3] The highway/byway method was based on SPP's method of cost allocation with two layers of costs: the highway (regional layer) and the byway (local layer). By eliminating the sub-regional layer, the injection-withdrawal embraced characteristics of the highway/byway method.

Process is today; meaning, a project would be submitted to the Midwest ISO and if it is determined through the MTEP Planning Process to meet the definition of UPPs, it would qualify for UPP treatment. A project meeting the characteristics of an UPP would be evaluated for its cost-effectiveness; if the process is cost-effective, then it would be placed into MTEP Appendix A and would be eligible for regional cost sharing.

Examples of projects that the Supporting Transmission Owners anticipate could become UPPs, subject to the independent evaluation and determination of the Midwest ISO through the MTEP Planning Process, are possibly a first phase of needed projects identified in the Regional Generator Outlet Study (RGOS), the Brookings Line or projects proposed by the Upper Midwest Transmission Development Initiative (UMTDI) through the MTEP Planning Process.

Under the TO proposal, generator interconnections below 345 kV would directly assign 100% of the costs for network upgrades to the generator. Network upgrades mean any additions, modifications and upgrades to the transmission system required at or beyond the point at which the interconnection facilities connect to the transmission system to accommodate the interconnection of the generating facility(ies) to the transmission system. For generator interconnections at 345 kV and above, 80% of the cost for network upgrades would be directly assigned to the generator and 20% would be assigned to load within the Midwest ISO footprint. If, however, the network upgrade is necessarily part of the UPP, the cost of the network upgrade would be added to the cost of the UPP and considered part of the UPP, and thus eligible for regional cost sharing.

Exhibit 9 shows different cost allocation methodologies yielding significantly different rates. For example, the TO proposal has a rate for Great River Energy of \$5.9/MWh compared to \$8.7/MWh under the March, 2010 Midwest ISO proposal.[4] An even more dramatic example shows MDU with a rate of \$5.6/MWh under the TO proposal vs. \$10.3/MWh with the original MISO I/W proposal. Similarly, Otter Tail has a rate of \$5.3/MWh vs. \$8.7/MWh and Heartland has a rate of \$3.7/MWh vs. \$6.9/MWh.

Clearly, the TO proposal addresses the Otter Tail issue by limiting cost sharing to projected overlay projects (overlays are similar to UPPs) and related under-build projects[5] only, regionalizing those costs rather than splitting the interconnection costs between the local pricing zone and the MISO footprint. Companies with low load densities would do better under the TO proposal. Some of the companies facing higher rates with the TO proposal include Big Rivers with an increase from \$3.4/MWh to \$5.3/MWh, Minnesota Power (\$4.9/MWh vs. \$6.4/MWh) and Southern Illinois Power Cooperatives (\$3.8/MWh vs. \$4.9/MWh).

Unlike MISO's original I/W cost allocation proposal, the TO proposal does not explicitly apply the I/W methodology to network upgrades for new generator interconnections unless they are an under-build project associated with the UPP. In addition, the TO proposal would not at this time include RECB I and II projects (baseline reliability and economic projects). Cost allocation for these projects would remain the same and may be addressed in a subsequent FERC filing. The RECB Task Force will decide after the filing whether to revisit the allocations for RECB I and II.

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[4] MISO Cost Allocation Proposal Comparisons (April 25, 2010). Table used 2024 Regional Generation Outlet Study (RGOS) forecast of new lines—work in progress.

[5] Under-build projects are defined in the April 13, 2010 TO proposal (page 4) as projects that are part of the package with the UPP. An under-build project would not have been needed in the UPP project time frame if the UPP project was not being constructed and is primarily 100 kV and above.

Exhibit 9

Direct and Indirect Charges to Load in 2024 Case with First Energy Excluded and Big Rivers and Dairyland Included*

Pricing Zone	CARP Proposal	Midwest ISO Proposal	TO Proposal
[1]	[14]	[15]	[16]
	$ per MWh	$ per MWh	$ per MWh
AMIL	5.8	6.3	5.7
AMMO	5.6	5.1	5.5
ATC	5.7	5.4	6.0
BREC	4.0	3.4	5.7
CWLD	6.5	5.5	6.4
CWLP	3.9	3.4	4.2
DPC	5.0	4.3	5.6
DUK	4.9	4.3	4.7
FE	0.0	0.0	0.0
GRE	6.2	8.7	5.9
HE	3.8	6.9	3.7
IPL	4.2	3.8	4.4
ITC	6.3	5.4	6.4
ITCM	5.8	6.9	6.3
METC	5.5	4.5	5.6
MEC	5.1	6.6	5.6
MDU	5.4	10.3	5.6
MP	6.9	4.9	6.4
MPW	3.7	3.4	3.6
NIPS	4.7	5.9	4.7
NSP	6.0	7.6	6.2
OTP	5.1	8.7	5.3
SIPC	4.4	3.8	4.9
SMMPA	5.7	4.6	5.5
VECT	4.2	3.6	4.3

2024 RGOS 345 kV Indicative Overlay adjusted to reflect Current Cost Estimates

*Includes Duke Ohio and Kentucky. On 5/20/10 Duke filed with Commonwealth of Kentucky to transfer its Kentucky assets to PJM by 1/1/12. Approval by state of Ohio is not required. Approval to transfer assets to PJM is required by FERC.

MISO's New Proposal

Shortly after the vote and based on the TO proposal, MISO developed another cost allocation proposal that focused on the UPPs. This proposal reflected substantial input from CARP and was presented May 13, 2010 to the RECB Task Force. MISO renamed UPP projects as Multi-Value Projects (MVP)—having a broader definition than just low/no carbon to also recognize regional reliability projects and projects providing incremental economic benefits. MISO defines MVPs as regional transmission plans that:

- Address renewable resource integration or other policy-driven generation shifts
- Provide other regional impact, such as congestion reduction, footprint reserve margin reduction, etc.
- Include both the major project element (typically higher voltage) along with the additional transmission needed to make it reliable; these elements in total would be referred to as a project (similar to today's Baseline Reliability Project Treatment)

An MVP has a capital cost of at least $20,000,000 or at least 5% of the constructing transmission owner's net transmission plant. The new MISO proposal (as of June 10, 2010) keeps the essence of I/W and calls for 100% of the costs to be regional throughout the footprint, but assigns 80% to load, exports and wheels and 20% to generation (the 20% is still being debated and could be reduced). The 80% assigned to load is based on a MVP usage rate (MWh). The remaining 20% comes from a regional MVP access rate based on interconnected MW. For the 20% component, MISO's proposal is to remove the "higher-of" pricing method that was included in their original March proposal for new generators. The same MVP access rate would be charged to both new and existing generation. There would still, however, be a mechanism to differentiate "free riders".

Upon commercial operation, interconnecting generations will be charged the MVP access rate and their network upgrade costs. GIPs would pay 100% for less than 345kV, and 90% for 345kV and above with 10% socialized through the MVP usage rate. In addition, MISO's new proposal calls for cost allocation for RECB 1 projects (baseline reliability) and RECB II projects (economic) to remain the same. Changes to RECB II projects would be filed later.

Too Many Moles to Whac?

Although it gathered substantial input from the stakeholder process, MISO ultimately is responsible for filing a proposal that makes the most sense for MISO. Clair Moeller, MISO Vice President of Asset Management, expressed his concern about the ability to satisfy the diverse set of stakeholders with a new cost allocation methodology. Regarding injection-withdrawal, "A lot of people like it, and a lot of people don't. At the end of the day, if it doesn't look there's enough buy-in for a new proposal, we would instead ask FERC to make our interim solution (90-10) permanent."[6] Moeller went on to say that MISO will not file a new methodology that could cause members to leave MISO and could "cause a significant erosion among our members."

It is apparent that each different cost allocation methodology has cost shifting with some winners and losers. Addressing one problem, such as the Otter Tail issue, only moves the burden to other utilities who perceive that burden to be unjust. Finding the cost allocation methodology that strikes an acceptable balance among all the stakeholders surely presents a challenge. Playing ATRR Whac-A-Mole has been no carnival for MISO, but the new MISO proposal salvaged elements of injection-withdrawal and appears to keep most of the moles underground (at least for now) to keep the Midwest ISO viable. MCR

[6] Electric Transmission Week page 1, April 19, 2010.

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