UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	))))	Docket No. ER10-1791-000

PROTEST OF THE INDUSTRIAL CUSTOMERS

Pursuant to Rule 211[1] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, the Coalition of Midwest Transmission Customers ("CMTC"), the Minnesota Large Industrial Group ("MLIG"), the Electricity Consumers Resource Council ("ELCON"), the Illinois Industrial Energy Consumers ("IIEC"), and the Wisconsin Industrial Energy Group ("WIEG") (collectively, "Industrial Customers") hereby file this Protest in the above-referenced proceeding.[2]

On July 15, 2010 the Midwest Independent Transmission System Operator, Inc. ("MISO" or "Midwest ISO") and the Midwest ISO Transmission Systems Owners[3] (collectively "Filing Parties") submitted the Filing, in accordance with the Commission's October 23, 2009 order in Docket No. ER09-1431-000,[4] to revise MISO's Open Access Transmission Tariff ("OATT"). In the application, the Filing Parties propose to: (1) establish a new category of transmission projects designated as Multi Value Projects ("MVPs") and a corresponding cost allocation

[1] 18 C.F.R. §385.211.
[2] As the name implies, the groups comprising the Industrial Customers consist of manufacturing, mining, and large commercial facilities that are energy-intensive and located in the MISO region. Each of the groups comprising the Industrial Customers has separately intervened or will be separately intervening in this proceeding.
[3] The Midwest ISO Transmission Owners are Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, Central Illinois Light Co. d/b/a AmerenCILCO, and Illinois Power Company d/b/a AmerenIP; American Transmission Company LLC; Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Southern Minnesota Municipal Power Agency.
[4] *Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,060, at P 1 (2009) ("October 23 Order").

methodology for such projects; (2) require that Generator Interconnection Projects ("GIP") arising within a defined time period share the costs of Network Upgrades on which they mutually rely; and (3) otherwise retain the cost allocation for Network Upgrades needed for GIPs that was conditionally accepted by the Commission in the October 23 Order.

In additional to the transmittal letter ("Transmittal Letter"), the application includes supporting documents as follows:

Tab A – Summary of Proposed Tariff Revisions

Tab B – Clean Tariff Sheets

Tab C – Redlined Tariff Sheets

Tab D – Ramey Testimony ("Ramey Testimony")

Tab E – Moeller Testimony ("Moeller Testimony")

Tab F – Lawhorn Testimony ("Lawhorn Testimony")

Tab G – Curran Testimony ("Curran Testimony")

Tab H – Laverty Testimony ("Laverty Testimony")

Tab I – Webb Testimony ("Webb Testimony")

Tab J – List of Starter Projects

Tab K – Midwestern Governors Association Letter

On July 19, 2010, as amended by an errata notice on July 20, 2010, the Commission set the due date for comments on the Application as September 10, 2010. Pursuant to the Commission's notice, Industrial Customers submit this Protest and the attached Affidavit of James R. Dauphinais ("Dauphinais Affidavit").

I. INTRODUCTION

The history of events leading to the Filing is lengthy and conveyed in detail in their Transmittal Letter on pages 4 through 11. For the sake of brevity, Industrial Customers will not repeat that history.

In the Protest that follows, Industrial Customers consider the requirements set forth by the U.S. Court of Appeals for the Seventh Circuit ("Seventh Circuit")[5] as such requirements relate to the Commission's adoption of a method to allocate the cost of high voltage transmission facilities. Industrial Customers conclude that these requirements and the evidence submitted in this proceeding preclude the use of the Filing Parties proposed "socialized" cost allocation methodology. Industrial Customers also conclude that the revenue responsibility for such costs must be allocated in accordance with "cost causation" principles. Industrial Customers believe that those results are compelled by the Federal Power Act's "just and reasonable" standard as developed and applied by the Commission and the Courts.

For several years, the Commission has advocated the use of a locational marginal pricing ("LMP") methodology and "uniform clearing prices" to inform customers, regulators and investors in MISO and elsewhere about how to most effectively deploy capital. A relative comparison of zonal LMPs is said to convey something about "congestion" or the economic effect of available resources that are unable to reach the market because of reliability-defined limits of the physical system.

What happens when the Filing Parties' socialized energy-based cost allocation method is laid on top of the LMP price signal? In the case of new transmission investment for high voltage transmission facilities, the socialized energy-based cost allocation method operates (by design) to ignore the relationship between the need for incremental investment, the demonstrable benefits,

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[5] *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (*"ICC"*).

and the resulting revenue responsibility derived from the application of rates and charges. Therefore, both on a stand-alone basis and from a broader perspective, the socialized energy-based cost allocation method of allocating responsibility for the cost of new investment is neither just nor reasonable.

There are parties who will likely urge the Commission to adopt the socialized energy-based cost allocation method reflected in the Filing. They will claim that this method is, administratively speaking, a convenient one. But any administrative convenience in the context of the Filing comes at the expense of ignoring cost causation principles and all the issues that must be addressed when these principles are honestly observed. The Seventh Circuit has commanded the Commission to do much more than to serve the goal of administrative convenience. The Commission must observe principles of cost-causation in assessing the justness and reasonable of a proposed allocation of transmission facility costs. The Filing does not abide by these principles. Accordingly, Industrial Customers urge the Commission to deny the relief requested in the Filing. Specifically, the Commission should find, as unjust, unreasonable, and unduly discriminatory, MISO's proposal to advance ill-defined public policy objectives by enabling certain transmission projects to obtain socialized cost allocations. Moreover, if such projects are enabled, the costs must not be allocated or recovered on a MWh basis as the Filing Parties propose. That aspect of the Filing, standing alone, renders it unjust and unreasonable.

II. PROTEST

A. Filing Parties' Proposed Cost Allocation Proposal, Which Is Based On Overly Broad Notions Of Regional Benefits And Socialized Costs, Has Not Been Demonstrated To Be Just And Reasonable.

Filing Parties propose to define a new class of transmission upgrades to be called multi-value projects ("MVPs") that are intended to support public policy objectives and affect multiple transmission zones.[6] According to the Filing Parties, the MVP project classification is intended to facilitate the integration of location-constrained resources, including renewable generation resources, support MISO member and customer compliance with renewable portfolio standards, address multiple reliability needs and economic opportunities, and strike a better cost allocation balance than the current rules.[7] The Filing Parties state that regional loads and exports are expected to be the biggest users of MVP projects and that economic studies conducted by MISO show that MVP projects will provide wide regional benefits such as reduced congestion costs, reduction in transmission losses, and reduced capacity requirements.[8]

Currently, MISO's tariff permits regional cost sharing for projects that satisfy criteria to be classified as either a Baseline Reliability Project[9] or a Regionally Beneficial Project.[10] For MVPs, the Filing Parties proposed that projects must meet at least one of three criterion to be designated as an MVP. A project can qualify as an MVP under Criterion 1 if the project is driven by the need to satisfy delivery of energy to support a documented public policy law or mandate.[11] A project can qualify as an MVP under Criterion 2 if the project provides economic value across multiple pricing zones.[12] A project can qualify as an MVP under Criterion 3 if it addresses a transmission issues to comply with reliability standards and provides economic value across multiple pricing zones.[13]

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[6] Transmittal Letter at 2.
[7] *Id*.
[8] *Id*. at 3.
[9] The costs of Baseline Reliability Projects are allocated among zones based upon a line outage distribution factor ("LODF") analysis to determine which zones are benefiting from the project.
[10] Curran Testimony at 29. For Regional Beneficial Projects Twenty percent (20%) of the cost for a Regionally Beneficial Project is allocated to all transmission customers through a system-wide rate. The remaining 80% of the project cost is allocated to all transmission customers in each of MISO's three planning sub-regions (West, East, and Central). The cost allocated to each of these sub-regions is based on the relative benefit each receives from the project, as determined by an economic benefit analysis.
[11] Curran Testimony at 30.
[12] *Id*.
[13] *Id*.

The Filing Parties propose to allocate the costs of MVP projects by socializing the costs across MISO's entire system. The entire cost of MVP projects would be allocated to load and exports based on their energy usage. The Filing Parties claim that allocating all of the costs of MVP projects to load and exports based upon energy usage is appropriate in that the benefits of MVP projects are regional in nature.[14] The Filing Parties attempt to justify their energy-based cost allocation by suggesting that a significant portion of the benefits of MVPs would occur at times other than peak demand.[15] The Filing Parties reason that MVP projects will facilitate greater dispatch of wind resources, which operate at greater capacity during off-peak hours.[16] Because the Filing Parties envision that MVPs may reduce generation production costs, they argue an energy-based allocation is reasonable.[17] The Filing Parties claim that anticipated production cost benefits will be spread equally across MISO's three regional planning regions roughly commensurate with the distribution of energy, which supports the broad socialization of costs.[18] The Filing Parties also claim their proposed cost allocation methodology would avoid involuntarily allocating costs to entities receiving no benefit and incorporates appropriate benefit metrics to determine MVP project benefits.[19] The Filing Parties recognize the courts have found that any cost allocation methodology must satisfy the requirement that the allocation of costs be at least roughly commensurate with benefits.[20] The Filing Parties also argue that the Commission has found that an integrated system such as MISO's benefits all users of the network.[21]

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[14] *Id*. at 28-29.
[15] *Id*. at 12.
[16] *Id*.
[17] *Id*.
[18] *Id*. at 23.
[19] Moeller Testimony at 4-5.
[20] Transmittal Letter at 12.
[21] *Id*. at 14.

The Filing Parties' cost allocation proposal is based on overly broad notions of regional benefits and has not been demonstrated to be just and reasonable. As discussed *infra*, the Filing Parties' cost allocation proposal would allocate costs to loads within the region even in instances in which MISO's own studies conclude there are **no** regional economic benefits and **no** benefits to the loads that are being allocated costs. These studies also do not demonstrate broad regional benefits. Further, the Filing Parties recognize that their proposal would result in a dramatic shifting to load certain costs that are presently allocated to interconnection generation resources, and the impacts from shifting these costs to loads could be substantial.[22] This shifting of costs would result from the MVP classification being applied to transmission projects that heretofore would, under MISO's currently approved tariff, only qualify as generation interconnection network upgrades. Far from being a regional benefit, such shifting of interconnection costs from the generation projects triggering the upgrade to load that may or may not benefit from the upgrades can only be appropriately characterized as an impermissible subsidy. FERC cannot accept the Filing Parties' proposal.

1. Socialization Of Costs May Occur Only When Benefits Are Broadly And Uniformly Attained.

The principle of "beneficiary pays" is well established through both court cases and Commission cases. The judicial application of the principle first developed in early natural gas pipeline cases, which have a similar investment profile to the long transmission lines currently under proposal. And the statutory "just and reasonable" standard for rates is the same under the Federal Power Act as it is under the Natural Gas Act. The long line of "beneficiary pays" cases trace their origin to a seminal 1945 Supreme Court decision that stated, in an opinion frequently

[22] Curran Testimony at 4.

cited by FERC, that "[t]he problem [to be addressed by a rate case] is to allocate to each class of the business its fair share of the costs."[23]

The *Colorado Interstate Gas* principles subsequently were elucidated in a series of cases decided by the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), beginning with *Algonquin Gas Trans. Co. v. FERC*[24] and including *Complex Consol. Edison Co. of New York v. FERC*[25] and *Transcontinental Gas Pipe Line Corp. v. FERC*.[26] All three cases involved allocating the costs of new facilities, with the D.C. Circuit addressing whether the costs of the new or expanded facilities should be allocated to the beneficiaries ("incremental pricing") or to all of the gas company's customers ("rolled-in pricing").

In all three cases, the court required FERC to "outline[ ] with reasonable particularity the system-wide benefits which each new facility produces" to justify rolled-in pricing.[27] Under these cases, there must be substantial and specific benefits to the system as a whole to justify socializing the costs of new facilities, otherwise those ratepayers that do not benefit subsidize those that do.[28]

The principle of "beneficiary pays" has been considered by the courts, particularly in electricity cases, under the rubric of "cost causation." As the D.C. Circuit has explained, although "just and reasonable" provides a "spartan" statutory standard, "FERC and the courts

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[23] *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 588 (1945).
[24] 948 F.2d 1305 (D.C. Cir. 1991).
[25] 165 F.3d 992 (D.C. Cir. 1999).
[26] 518 F.3d 916 (D.C. Cir. 2008).
[27] *Algonquin*, 948 F.3d at 1313, 1315 (this is not a theoretical exercise, but a question of fact dependent on "the impact the order would actually have on ultimate consumers"); *see Complex Consol.*, 165 F.3d at 998, 1006 (affirming FERC's holding that rolled-in rates were not just and reasonable based on FERC's conclusion that "the alleged system benefits postulated by JMC Power [were] insubstantial"); *Transcontinental*, 518 F.3d at 920 (affirming FERC's order adopting incremental rates where "FERC . . . correctly concluded that existing customers would have . . . subsidized the Cherokee shippers if [the gas company] had been allowed to roll in rates").
[28] *See, e.g.*, *Transcontinental*, 518 F.3d at 921 ("Rolling in the power costs of the Cherokee compressors forced existing Transco customers to subsidize the power costs of compressors they had no need for . . . ."); *Algonquin*, 948 F.2d at 1313 ("What we do require, however, is that the Commission, before ordering a roll-in . . . offer more than a conclusionary statement that the existence of system-wide benefits renders it unjust to allocate facilities costs incrementally."); *Complex Consol.*, 165 F.3d at 997 ("[T]he weight of the evidence favored the conclusion that the [new] facilities provided neither operational benefits nor additional reliability to Tennessee's system customers.").

have added flesh to these bare statutory bones, establishing what has become known . . . as the ‘cost-causation’ principle.”[29] The cost-causation principle is the “touchstone in any legal analysis of FERC-approved rate schemes,” and it requires “that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.” *Id.; see also Village of Bethany v. FERC*, 276 F.3d 934, 937 (7th Cir. 2002) (“The overriding policy concern in a ratemaking proceeding is to establish rates that require each customer to bear a fair and proportional share of . . . costs.”).

The D.C. Circuit has stated that compliance with the cost-causation principle must be evaluated “by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.”[30] The court in *Midwest ISO* described FERC’s cost-causation principle as “requir[ing] that all approved rates reflect to some degree the costs actually caused by the customers who must pay them.… Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or the benefits drawn by that party.”[31]

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[29] *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992).
[30] *Midwest ISO Transmission Owners*, 373 F.3d 1361, 1368-69 (D.C. Cir. 2004).
[31] *Id.* (Citations omitted); *see also United Distribution Cos. v. FERC*, 88 F.3d 1105, 1188-89 (D.C. Cir. 1996) (“[c]ost causation correlates costs with those customers for whom a service is rendered or a cost is incurred”); *Cities of Riverside and Colton, California v. FERC*, 765 F.2d 1434, 1439 (9th Cir. 1985).

Although FERC need not "allocate costs with exacting precision,"[32] it may depart from the principle of cost-causation only in extraordinary circumstances and for a limited purpose.[33] A rate design that results in some ratepayers subsidizing the service of others is *prima facie* inconsistent with cost-causation and presumptively invalid.[34]

The Commission has described its "long standing policy" on utility cost allocation in these words: "Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the cost to serve each class or individual customer."[35] FERC has treated as black-letter law the principle that customers using a facility or service, or benefiting from a facility or service, must pay their fair share of the costs of the facility or service. FERC refers to this principle as "cost causation."[36] Implicit in the cost-causation analysis is the principle that each "customer pay[s] for the service [it] receive[s] and do[es] not subsidize service rendered on behalf of others."[37]

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[32] *Midwest ISO Transmission Owners*, 373 F.3d at 1369.
[33] *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 707 (D.C. Cir. 2000); *see also Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002) (remanding to FERC to explain why it did not apply "a different method of refunds, based more closely on cost-causation principles"). Although cases such as *Midwest ISO Transmission Owners v. FERC* or *Western Massachusetts Electric Co. v. FERC* have approved system wide cost allocations, those allocations, unlike the allocation of transmission investment at issue here, were found to involve costs that created identifiable system-wide benefits. In *Midwest ISO Transmission Owners v. FERC*, the court identified both the substantial record evidence demonstrating that all parties being charged the cost adder at issue received benefits from the existence of the Midwest ISO and the fallacy of appellees' argument to the contrary. 373 F.3d at 1371. In *Western Massachusetts Electric Co. v FERC*, the choice was between assigning costs to an interconnecting generator or rolling the costs into a single utility's transmission rates. The court pointed to specific evidence, including load flow studies, supporting the benefits provided to all users of the utility's transmission system. *Western Massachusetts Electric Co.*, 165 F.3d at 927-28.
[34] *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 188 (D.C. Cir. 1986); *Nat'l Ass'n of Sec. Dealers, Inc. v. SEC*, 801 F.2d 1415, 1420 (D.C. Cir. 1986) ("Avoidance of cross-subsidization of services is a legitimate, non-arbitrary reason for requiring difficult cost allocations.").
[35] *New Dominion Energy Cooperative*, 122 FERC ¶ 61,174, P 41 (2008), *citing Alabama Electric Cooperative, Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).
[36] *See, e.g., California Power Exchange Corp.*, 106 FERC ¶ 61,196, P 17 (2004), (the "well-established principle of cost causation requires that costs should be allocated, where possible, to customers based on customer benefits and cost incurrence"). *See also CAISO*, 103 FERC ¶ 61,114, P 26 ("[w]hile this fundamental idea of matching costs to customers is often referred to in terms of cost causation, it has also often been described in terms of the costs which 'should be borne by those who benefit from them'" (*quoting Gulf Power Co. v. FERC*, 983 F.2d 1095, 1100 (D.C. Cir. 1993))).
[37] *Empire State Pipeline and Empire Pipeline, Inc*., 116 FERC ¶ 61,074 at P 115 (2006).

Moreover, the Commission has found that a claim of "generalized system benefits" is insufficient to justify charges – there must be a tangible, non-trivial benefit supported by the record.[38] The Commission also has acknowledged that the principle of fairly allocating transmission costs among those who use and benefit from transmission facilities fully applies to RTO transmission rates.[39]

These principles have been invoked repeatedly by the Courts of Appeal on review of Commission orders, most recently by the Seventh Circuit.[40] The Seventh Circuit unambiguously explained how this principle must be applied in practice:[41]

> We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. If it cannot quantify the benefits to the [M]idwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[42]

Practical considerations of economic efficiency and public policy also counsel in favor of a "beneficiary pays" model of cost allocation. In a nutshell, the "beneficiary pays" model establishes more economically justified incentives for new construction than cost allocation

[38] *See e.g.*, *FPL Energy Marcus Hook, L.P. v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,289 at P 50 (2008) (noting that "[e]very addition to the system could be characterized as providing some possible intangible system benefit by adding transmission capacity redundancy"); *Transcontinental Gas Pipe Line Corp.*, 112 FERC ¶ 61,170, 61,924-25 (2005).
[39] *See Alliance Companies*, 94 FERC ¶ 61,070, 61,311-13; *Midwest Independent Transmission System Operator, Inc.*, 104 FERC ¶ 61,105, PP 50-51; *Ameren*, 105 FERC ¶ 61,216, PP 32, 57; *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,262, P 6 n.10 (2004) (approving the Going Forward Principles).
[40] *ICC*, 576 F.3d at 476 (*citing Midwest ISO Transmission Owners*, 373 F.3d at 1368).
[41] Industrial Customers recognize that, notwithstanding these admonitions from the Seventh Circuit, the Commission has recently approved the socialized allocation of costs for the Southwest Power Pool. *Southwest Power Pool* 131 FERC ¶ 61,252 at P 80 (June 17, 2010) (citations omitted).
[42] *Id.* at 477 (citations omitted).

models that socialize transmission costs, while also minimizing public opposition to potentially beneficial projects.

The "beneficiary pays" model of cost allocation results in greater economic efficiency by retaining a direct tie between the costs and the benefits of a given project, enabling the potential beneficiaries to appropriately determine whether the costs are worthwhile. Socialization distorts the economic incentives of participants by insulating the beneficiaries from the full costs.[43] When market beneficiaries are not required to bear the full costs of a proposed project, they may push forward with a project even if it is economically inefficient (i.e., total costs exceed total benefits) because their private gain exceeds their reduced costs. On the other hand, those who are allocated costs based on actual, demonstrable benefits are less likely to object to the construction of new transmission facilities than those who are allocated costs based on an assumption that they will receive some general, unquantifiable benefit. The "beneficiary pays" model is, therefore, more likely to reduce controversy and assure that future transmission would be built where the costs truly are justified. The construction of transmission is perhaps the most controversial form of electric utility investment. Socialization of costs simply increases the coalition of interests that will oppose potentially beneficial system upgrades.

Industrial Customers believe that getting transmission cost allocation right is essential to ensuring that all consumers benefit from the lowest cost energy alternatives. Industrial Customers support the cost-effective development of clean energy resources -- both local and remote -- and any necessary increases in transmission capacity. Developing such resources at the lowest possible cost, however, requires that a cost allocation method send appropriate price signals for efficient siting decisions.

[43] *See Certification of New Interstate Natural Gas Pipeline Facilities*, 90 FERC ¶ 61,128, at 61,391-93 (2000) (Clarified Policy Statement) (recognizing that subsidies send the wrong price signals to the market, leading to inefficient investment decisions).

The Filing Parties recognize their cost allocation proposal is the result of the perceived need to facilitate interconnection of large amounts of wind resources in the region. Thus, the cost allocation debate is, first and foremost, a generation-to-load or generation-to-market issue. As such, the costs of transmission facilities should be allocated and recovered in the same manner as traditional generation-to-load and interconnection projects. This is especially true if the transmission facilities would not have been built in the near future <u>but for</u> the need for wind integration with its markets. For that reason, such transmission facilities cannot be treated as pure public goods worthy of public funding or broad-based socialization in rates.

Ultimately, then, the Commission may only approve a cost allocation method based on a factual demonstration of consistency with cost causation. In particular, "mere reliance on economic theory cannot substitute for substantial record evidence."[44] To fulfill this precedential mandate, the Commission cannot avoid "comparing the costs assessed against a party to the burdens imposed or benefits received by that party" "based on substantial evidence in the record."[45]

2. The Studies Conducted To Date By MISO Do Not Demonstrate Broad Regional Benefits.

The evidence submitted by the Filing Parties in this proceeding does not support a broad socialization of costs associated with MVP projects. The studies conducted to date by MISO do not provide evidence of regional benefits sufficient to justify allocating 100% of the costs of MVPs regionally to load based upon energy usage.

The Filing Parties proffer the testimony of three witnesses to support its claims of broad regional benefits associated with MVP. The first, Clair J. Moeller, simply makes an unsupported conclusion in his testimony that the Filing Parties' cost allocation proposal allocates costs to

[44] *Elec. Consumer Resource Council v. FERC*, 747 F.2d 1511, 1514 (D.C. Cir. 1984).
[45] *Illinois Commerce Com'n*, 493 F.3d at 477-78.

those entities benefiting from the construction of facilities in a manner roughly commensurate with the benefit.[46]

The Filing Parties witness John Lawhorn describes the production cost modeling undertaken by MISO as part of its studies:

> The Midwest ISO annual potential adjusted production cost savings from the MVP starter projects ranged from $297 million to $423 million in year 2015 and $402 million to $1.3 billion in year 2025 under the five future scenarios. Each Midwest ISO Planning Region has positive adjusted production cost savings potential under nearly all scenarios. The distribution of savings is generally evenly divided through the regions with slightly more savings in the Midwest ISO East Planning Region.

Lawhorn Testimony at 13. Mr. Lawhorn states that the savings are "evenly divided" among MISO's three planning regions. However, he offers no evidence as to whether the distribution of purported benefits is generally evenly divided on an intraregional basis within MISO's planning regions, and it cannot simply be assumed this is the case.

Further, a production cost model simulates the costs of operating the generation fleet across the region.[47] It does not represent the simulated costs to load. Load cost is the cost that load serving entities pay to have their load served; it is the MW of load multiplied by the load-weighted LMP. MISO did conduct studies estimating load cost associated with the MVP starter projects. These studies show that:

> Midwest ISO annual load cost savings potential associated with the MVP starter projects ranged from $**14 million** to $984 million in year 2015 and **-$19 million** to $2 billion in year 2025 under the five future scenarios. A negative load cost savings is the result of neighboring pools having access to less expensive generation that was previously unavailable due to transmission constraints. As outside pools access less expensive generation their load costs decrease; however, the load costs for the source pool increase.

[46] Moeller Testimony at 4.
[47] Lawhorn Testimony at 4.

Lawhorn Testimony at 13 (emphasis added). Thus, in some scenarios studied by MISO, the benefit to load in the MISO region ranged from *de minimus* ($14 million) to negative (-$19 million). These study results strongly suggest the Filing Parties' cost allocation proposal will result in load in the MISO region underwriting the cost of transmission upgrades in the region that simply allow greater exports by MISO generators. As importantly, Mr. Lawhorn offers no evidence whatsoever that the distribution of load cost savings (or the additional costs in some scenarios) will be generally distributed roughly commensurate with the Filing Parties' proposed cost allocation. This reason alone supports a conclusion that the Filing Parties' proposed cost allocation methodology is not just and reasonable. Further, requiring load to underwrite transmission investments to expand export opportunities for generation resources is the antithesis of a cost allocation methodology that allocates costs to those benefiting, as required by court precedent.

Mr. Lawhorn also identifies that MVP starter projects have the potential to reduce average losses from 3.09% to 2.82% in 2015 and provide estimated savings of $68 million. Under a study assuming the construction of a 765kV overlay, the potential loss savings in 2025 is estimated by Mr. Lawhorn at $104 million. However, Mr. Lawhorn provides <u>no</u> evidence that the benefits of reduced losses will be generally distributed across the MISO region. MISO's energy market, which relies on locational marginal prices, reflects the use of marginal losses. When marginal losses are used, the cost of losses varies throughout the network and customers are charged more for losses than the actual cost of losses. The over-collected losses are rebated back to load as a credit, but not in proportion to their actual losses because the Commission has determined this would eliminate an important pricing signal.[48] The Commission has recognized this method of refunding over-collected losses may result in larger entities within a balancing authority receiving more of a refund than deserved, while smaller entities with a balancing authority might receive less than deserved.[49] Given the use of marginal losses within the region, it cannot simply be assumed that a reduction in average system losses as a result of transmission upgrades provides widespread regional benefits necessary to support a broad-based socialization of the costs of MVPs.

Mr. Lawhorn also testifies that reducing transmission losses will reduce the level of generation capacity reserves necessary to maintain system reliability. He states that MISO studies indicated that capacity reserves may be reduced by 100 MW in 2015, which can provide $110 million in annual savings based upon an assumed $960,000 per MW-year cost of new entry.[50] However, the cost of new entry cited by Mr. Lawhorn in his testimony grossly overstates (by a factor of ten) reasonable estimates of the cost of new entry. In fact, this value significantly exceeds the estimated costs of new entry that MISO has requested the Commission accept in other proceedings[51] as well as recent estimates from the MISO's independent market monitor. Using the far more realistic cost of new entry of $90,000 per MW-year that was proposed by MISO last year would suggest that a 100 MW reduction in capacity reserves could reduce system costs by approximately $9.6 million dollars annually. But there is no evidence provided by the Filing Parties that a reduced capacity margin obligation will provide broad benefits across the MISO region. Under the MISO's current resource adequacy construct, MISO will

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[48] *Atlantic City Electric Company, et al.* 115 FERC ¶ 61, 132 at P 24 (2006).
[49] *Wisconsin Public Power Inc. v. FERC*, 493 F.3d 239, 377 (D.C. Cir. 2007).
[50] Lawhorrn Testimony at 15.
[51] *See Midwest Indep. Trans. Sys. Operator, Inc.*, Docket No. ER08-394-007, 009 (Nov. 19, 2008); *Midwest Indep. Trans. Sys. Operator, Inc.*, ER10-2090-0000 (Aug. 2, 2010).

impose a higher reserve margin obligation on a sub-region in the event that MISO's loss of load equivalent ("LOLE") studies identify transmission constraints that limit imports into the region.[52] Further, and much to Industrial Customers' chagrin, the Commission has directed MISO to consider whether locational capacity elements should be incorporated into the MISO resource adequacy construct.[53] Thus, it cannot simply be assumed that a transmission upgrade in any particular location in the MISO region will permit MISO to reduce capacity margin obligations uniformly throughout the region.

The Filing Parties' witness Jennifer Curran reiterates many of the same benefits claims alleged by Mr. Lawhorn – i.e., touted benefits associated with lower production costs, reduced losses, and lower capacity margins. Ms. Curran's testimony largely regurgitates Mr. Lawhorn's testimony in these areas, including his erroneous assumptions regarding the cost of new entry. However, Ms. Curran also claims that MVP projects may provide reliability benefits in several ways, implying that such reliability benefits support a broad socialization of the cost of MVPs.[54]

As the courts have recognized, any transmission upgrade can be claimed to have produced some reliability benefit because the transmission grid is an integrated network. Mere claims of reliability benefits do not, however, provide sufficient support to justify socialization of the costs of all transmission upgrades:

> No doubt there will be *some* benefit to the Midwestern utilities just because the network *is* a network, and there have been outages in the Midwest. But enough of a benefit to justify the costs that FERC wants shifted to those utilities? Nothing in the Commission's opinions enables an answer to that question. Although the Commission did say that a 500 kV transmission line has twice the capacity of a 345 kV line, it added that "the *reliability* of 500 kV and above circuits in terms of momentary and sustained interruptions is 70 percent more reliable than 138 kV circuits and 60 percent more than 230 kV circuits on a per mile basis," *PJM*

[52] Module E, MISO Tariff § 68.3.
[53] *Midwest Indep. Trans. Sys. Operator, Inc.*, 126 FERC ¶ 61,144 (2009) and 131 FERC ¶ 61,128 (2010).
[54] Curran Testimony at 27.

> *Interconnection, L.L.C.*, *supra*, 119 F.E.R.C. ¶ 61,063, p. 23; 122 F.E.R.C. ¶ 61,082, p. 16 (emphasis added)—but did not compare the reliability of a 500 kV line to that of a 345 kV line, even though network reliability is the benefit that the Commission thinks the midwestern utilities will obtain from new 500 kV lines in the East.
>
> Rather desperately FERC's lawyer, and the lawyer for the eastern utilities that intervened in support of its ruling, reminded us at argument that Commission has a great deal of experience with issues of reliability and network needs, and they asked us therefore (in effect) to take the soundness of its decision on faith. But we cannot do that because we are not authorized to uphold a regulatory decision that is not supported by substantial evidence on the record as a whole, or to supply reasons for the decision that did not occur to the regulators. E.g., 5 U.S.C. § 706; *Bethany v. FERC*, 276 F.3d 934, 940 (7th Cir. 2002); *Central Illinois Public Service Co. v. FERC*, 941 F.2d 622, 627 (7th Cir. 1991); *Pacific Gas & Electric Co. v. FERC, supra*, 373 F.3d at 1319. The reasons that did occur to FERC are inadequate.[55]

In the case here, MISO has not demonstrated that widespread, uniform, and actual reliability benefits will flow from MVPs. Accordingly, socialization of the costs of MVPs cannot be sustained.

a. Under Some Scenarios, The Studies Show Net Negative Impacts In Some Or All Regions Of MISO.

Rather than demonstrating that MVPs will result in broad regional benefits across the MISO region, the studies conducted by MISO show that in some scenarios there may be higher costs to load within the MISO region if the facilities are constructed. As indicated in the testimony of Mr. Lawhorn, some scenarios identified load cost savings of as little as $14 million in 2015 and higher costs of $19 million in 2025.[56] An estimate of higher cost to load indicates that the transmission upgrades are allowing in-region generation to be exported to higher cost neighboring regions, thus increasing the price of electricity for customers in the MISO region. This is precisely the fact-pattern that prompted the Seventh Circuit to send the Commission back to the drawing board to align cost responsibility with cost-causation.

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[55] *Illinois Commerce Com'n v. FERC*, 576 F.3d 470, 477 (D.C. Cir. 2009).
[56] Lawhorn Testimony at 14.

b. Filing Parties' Proposal Would Allow Regional Cost Sharing Of MVPs Even In Situations When Costs Clearly Exceed Benefits.

Further, as discussed in the testimony of Jennifer Curran, MISO contemplates approving MVPs even in circumstances in which a particular project does not pass an economic benefit test, if the project ensures reliability or is necessary to satisfy regional policy requirements.[57] While Industrial Customers do not quibble that under such circumstances the construction of transmission upgrades may be necessary, it does not follow that such projects are appropriate for regional cost sharing. In the absence of broad economic benefits, claims of reliability do not provide sufficient justification for broad socialization of costs. Further, in the absence of broad regional economic benefits, the costs of facilities constructed to satisfy state renewable portfolio requirements should be allocated to either the associated renewable generation facilities or the transmission customers that are specifically subject to the state renewable portfolio requirements that caused the need for or benefit from the facilities.[58]

c. The studies rely upon outdated load forecast.

The studies undertaken by MISO to support its argument that MVPs provide broad regional benefits reflected five scenarios to project public policy and economic impacts.[59] The five scenarios included: (1) the Organization of MISO States ("OMS") Cost Allocation and Regional Planning ("CARP") Business as Usual ("BAU") Future; (2) the CARP Renewable Portfolio Standard ("RPS") Future; (3) the CARP RPS, Carbon Cap, Smart Grid, and Electric Vehicle Future; (4) the Planning Advisory Committee ("PAC") BAU with Mid-Low Demand

[57] Curran Testimony at 7.

[58] A case in point is the proposed transmission project in the Michigan thumb region discussed on page 21 of the testimony of Clair Moeller. Because Michigan is an electrical peninsula, and this project does not expand the electrical ties of Michigan to the rest of the MISO system, the project is not capable of delivering broad regional economic benefits. Further, the project has been proposed to facilitate the interconnection of 1,260 MW of wind generation seeking to locate in the thumb region of Michigan. This project would not be necessary "but for" the current and planned wind generation facilities seeking to interconnect in the region.

[59] Lawhorn Testimony at 10.

Future; and (5) the PAC Carbon Cap and Nuclear Generation Future.[60] In all cases, MISO relied upon peak demand and load forecasts provided by MISO load serving entities for resource adequacy, which were then scaled to reflect growth rates in future years.[61] The Filing Parties acknowledge that it is unlikely that the future will exactly match any one of these scenarios, but suggest it is highly likely the future will be within the bounds of the assumptions reflected in these studies.[62]

New information developed by MISO suggests these assumptions are no longer correct, and that the demand and energy forecasts relied upon by MISO in its transmission planning process are substantially overstated. In order to improve its transmission planning process, MISO commissioned Global Energy Partners ("GEP") to undertake a study of the potential impacts of demand respond and energy efficiency in the MISO region.[63] The purpose of the study was to develop better estimates of the impacts of demand response and energy efficiency programs in order to incorporate these results into MISO's transmission planning process. Historically, MISO relied upon load forecasts provided by load serving entities that were escalated in future years based upon growth estimates as previously noted, and then assumed a reduction in sales and peak demand of 1% each year to estimate savings from demand response and energy efficiency programs.[64]

The GEP Assessment of Demand Response and Energy Efficiency Potential for the Midwest ISO concludes that there will be significant impacts from demand response and energy efficiency measures in the MISO region and these impacts are likely to offset virtually all of the

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[60] Id.
[61] Id at 8.
[62] Id at 12.
[63] A copy of the study is posted on MISO's website at: http://www.midwestmarket.org/publish/Document/ff748_12aaa1280c5_-7fe50a48324a?rev=1 ("Assessment of Demand Response and Energy Efficiency Potential for the Midwest ISO") (last visited August 23, 2010).
[64] Assessment of Demand Response and Energy Efficiency Potential for the Midwest ISO, Executive Summary at page v.

peak demand growth over a twenty year horizon, and offset a significant portion of the growth in energy usage. Specifically, the report estimates that demand response measures will reduce peak demand by 20,044 MW in 2030, which more than offsets the projected increase in the baseline peak demand forecasts from 98,963 MW to 116,165 MW in 2030.[65] Energy savings from demand response and efficiency measures are expected to reach a level of 58,605 GWH by 2030. This reduces the estimated growth in energy sales (465,022 GWH in 2010 increasing to 567,096 GWH in 2030) over the twenty year period by 50%.[66]

In light of the significant changes in forecast peak demand and energy usage now known to MISO, it is unreasonable to utilize the results of historical studies that assume significantly higher peak demand and energy usage to justify the need for new transmission projects, as well as to identify what regions of MISO (if any) may be expected to receive benefits from such projects. In addition to other recommended changes to the Filing Parties' proposal, the Commission should direct MISO to incorporate the results of the MISO-commissioned GEP analysis into its current transmission expansion plan (MTEP10) before approving any projects for regional cost sharing, as the updated study results may obviate the need for the expansion project.

3. Unless Beneficiaries Of New Transmission Facilities Pay The Costs Of Transmission, Then A Cost-Effectiveness Assessment Cannot Ensure The Right Resource Choices Based On Total Delivered Costs.

The Filing Parties acknowledge that the projects they have identified as likely MVP starter projects have been proposed primarily to facilitate the interconnection of new wind generation facilities.[67] Further, the Filing Parties make no attempt to hide the fact that the proposed allocation of the entire costs of MVPs to load will shift to load a significant portion of

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[65] *Id*.
[66] *Id* at page vii.
[67] Curran Testimony at 22.

the costs that wind generation resources would otherwise incur, easing the burden of interconnection to the generators in the queue.[68] This admission by the Filing Parties is telling, in that MISO's current tariff does not permit MISO to allocate the cost of network upgrades to interconnecting generation resources unless MISO determines the transmission upgrade is not necessary "but for" the interconnecting generator. This is a standard the Commission has enforced in practice.[69]

It is important that the actual delivered cost of electricity from new resources be allocated to the entities that are intended to benefit directly. The result ensures the alignment of cost responsibility with cost causation. If remotely located generation resources provide the most cost effective result, then transmission to deliver the generation to load should be built. However, the only way to properly identify if the remote generation is the most cost effective option is to make sure that any network upgrades not necessary "but for" the generator interconnection are directly allocated to the generation. To do otherwise creates a subsidy that is both contrary to Commission's pro-competition electricity policies (including the whole paradigm of LMP) and results in unlawful discrimination.

The decision on where to locate any new generation resource inherently involves tradeoffs. For example, a coal-fired generation facility can decide to locate near its mine-based fuel source, which will minimize the transportation cost of its fuel. However, if that location is remote from load and lacks adequate transmission facilities, it may require significant transmission upgrades in order for the output of the generation resource to be deliverable. However, if the costs of such transmission upgrades are socialized, rather than directly allocated

[68] *Id.*
[69] *See Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,019 at P24 (October 9, 2009).

to the beneficiaries, the generation owner has no incentive to discipline its decision on where to locate.

These principles apply equally to the large number of wind resources in MISO's interconnection queue, many of which are being pursued on a speculative basis, and for which adequate transmission infrastructure may not exist. Many of these resources are seeking to locate in areas within the MISO region in which the wind potential is greatest. However, if these wind resources are given a free pass and avoid any of the costs of network transmission upgrades that are not necessary "but for" their preferred siting location, there is nothing to discipline siting decisions. Further, socializing the costs of MVPs intended to facilitate the interconnection of wind resources does nothing to ensure that cost-effective generation gets built. For customers, it is a "lose lose" proposition.

4. Building A National Extra High Voltage (EHV) Transmission Network, Based On Pure Speculation About Generation Siting, Is A Fundamental Departure From Established Transmission Planning Principles And Would Likely Result In Wasteful Capital Investment.

The MVP starter projects identified by the Filing Parties represent the initial steps associated with ambitions to facilitate a much larger extra high voltage transmission overlay, as discussed in the testimony of Clair Moeller.[70] If the Commission were to approve the Filing Parties' tariff language associated with MVPs, it would vest MISO with virtually unfettered discretion as to the type of projects that could qualify as an MVP under Criterion 1:

> Criterion 1 - The project must be developed through the transmission expansion planning process for the purpose of enabling the transmission system to deliver energy reliably and economically support documented energy policy mandates or laws that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.[71]

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[70] Moeller Testimony at 12.
[71] Proposed Midwest ISO Tariff at Original Sheet No. 3451A.

Any network transmission upgrade will arguably result in a network that is more reliable. Further, it would be MISO's sole judgment as to what constitutes a "documented energy policy mandate."

The Filing Parties' MVP proposal is a marked departure from traditional planning in that it would allow MISO to approve construction of new transmission projects that are based on speculation as to where and whether generation will get built, rather than on solid commitments or even expressions of interests by generation owners on locations to interconnect. The first likely MVP project, which is discussed in the Filing Parties' testimony, illustrates this point.[72] MISO has initiated review of the ITC Michigan Loop Project through an out-of-cycle review and has recommended that the MISO Board of Directors approve this project as an MVP. This project involves the planned construction of four new 345 kV circuits in the thumb region of Michigan.[73] This project is designed to accommodate the interconnection of up to 4,236 MW of wind generation in the region.[74] However, presently, MISO has interconnection requests for only 1,260 MW of generation resources in this region. Accommodating even the current 1,260 MW of generation in the interconnection queue would require significant network upgrades.[75] However, rather than designing the project to accommodate the known interconnection requests, the project is being oversized with four 345 kV circuits based

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[72] Moeller Testimony at 21.
[73] Study documents associated with this project are posted on the MISO website at: http://www.midwestmarket.org/publish/Document/ff6bb_1280201754d_-7d630a48324a?rev=1 (last accessed August 13, 2010).
[74] Moeller Testimony at 21.
[75] *See* ITC Transmission/METC, and Wolverine Power Supply Cooperative, Inc., Michigan Wind Zones Transmission Analysis at page 17. "[N]umerous generation interconnection studies have documented the fact that there is essentially no additional transmission capacity available in the Thumb area." A copy of this report is posted on MISO's website at: http://www.midwestmarket.org/publish/Document/ff6bb_1280201754d_-7f1a0a48324a?rev=1 (last accessed August 13, 2010).

upon speculation that additional generation project will interconnect in the thumb region.

Building transmission projects based upon pure speculation on generation siting is a fundamental departure from traditional transmission planning principles. It will lead to wasteful capital investment as inevitably some guesses about the location of future generation will ultimately turn out to be incorrect. Moreover, the Filing Parties' cost allocation proposal would conscript captive end use customers into involuntary investors in projects that have not been demonstrated to be used and useful.

If Commission and the Filing Parties want to encourage speculative transmission investment to facilitate the potential to interconnect generation resources, there are alternative tools at the Commission's disposal that do not require conscripting captive end use customers, such as through the merchant transmission process, in which the developer assumes the financial risks associated with the project.[76]

In fact, the Filing Parties' proposed MVP status is closely analogous to merchant transmission facilities and should be treated in the same manner for cost allocation purposes. MVP proposals, much like merchant facilities, are by their very nature speculative and not based on the same level of scrutiny and demonstrated need as transmission approved at the regional level. In addition, the MVP proposal is based on sources of generation that, while potentially beneficial to some load and may offer competitive alternatives to existing supply, is nevertheless unproven and not based on established need. As the Commission has stated in the context of merchant transmission projects, while they have the ability to "expand[] competitive generation alternatives for

[76] *See, e.g., TransEnergie U.S., Ltd.*, 91 FERC ¶ 61,230 (2000); *Northeast Utilities Svs. Co.*, 98 FERC ¶ 61,310 (2002).

customers and meet[] reliability needs" on one hand, they will only be approved "without posing additional, unreasonable risks or costs" on the other.[77] As such, the Commission should not permit MISO to deviate from the Commission's merchant transmission policies for its proposed MVP class of transmission facilities.

The Commission should require MVPs to adhere to the same ten obligations that the Commission applies to proposals for merchant transmission projects within RTOs.[78] The Commission's ten criteria for evaluating merchant transmission are as follows: (1) the merchant transmission facility must assume full-market risk; (2) service should be provided under the OATT of the ISO or RTO that operates the merchant transmission facility and operational control should be given to the ISO/RTO; (3) the merchant transmission facility should create tradable firm secondary transmission rights; (4) an open season should be employed to initially allocate transmission rights; (5) results of the open season should be posted on OASIS and filed in a report to FERC; (6) affiliate concerns should be adequately addressed; (7) the merchant transmission facility should be subject to market monitoring for market power abuse; (8) the merchant transmission facility should not be able to preclude access to essential facilities by competitors; (9) physical energy flows on the merchant transmission facilities should be coordinated with and subject to reliability requirements of the relevant ISO or RTO; and (10) the merchant transmission facility should not impair pre-existing property rights to use the transmission grids of interconnected RTOs or utilities.[79]

From these ten criteria, at least four are directly relevant to the transmission cost allocation and cost-causation principles at issue in this proceeding. For example, as the

[77] *Id*. at P 24.
[78] *See Neptune Regional Trans. Sys., LLC* , 96 FERC ¶ 61,147, *order on* reh'g, 96 FERC ¶ 61,326 (2001)("Neptune"); *Montana Alberta Tie, Ltd*., 116 FERC ¶ 61,071 at P 26 (2006).
[79] *Id*.

first and overarching consideration, the Commission requires that merchant transmission facilities assume "full market risk."[80] As the Commission explained in *Neptune*:[81]

> As a merchant project with the authority to determine the project's size and to negotiate rates, Neptune must be prepared to bear 100 percent of the risks of constructing the project. If Neptune believes that its project provides measurable benefits on the systems to which it connects, Neptune is free to negotiate with the various grid operators to obtain financial support for the project. However, if those negotiations are unsuccessful, Neptune may not rely on this Commission to compel payment for any claimed benefits. Neptune's decision to proceed with its plans should be based solely on the value of its private market negotiations. In sum, we will not guarantee compensation for a merchant transmission project while allowing that project to retain both its at-risk status and the authority to determine project size and to negotiate rates.

In addition, the merchant facility must create tradable firm secondary transmission rights and post the results of the open season in order to ensure that the allocation of transmission rights was proper and is public.[82]

Recently, the Commission elaborated on its cost allocation and cost causation principles for planned and regionally-approved transmission.[83] In its *Transmission Planning and Cost Allocation* Notice of Proposed Rulemaking, the Commission distinguished the more traditional transmission, approved as part of a regional planning process, from purely merchant facilities, and found that "because a merchant developer assumes all financial risk for developing its project and constructing the proposed facilities," it would be unnecessary for it also to be further required to adhere to cost allocation methods ordinarily utilized when building new transmission in RTOs.[84] Said differently, costs should be shared if need has been demonstrated and vetted through a transmission expansion plan, but cost-sharing is not appropriate where such safeguards

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[80] *Id*. at P 26.
[81] 96 FERC ¶ 61,634.
[82] .*Montana Alberta Tie, Ltd.*, at P 26.
[83] *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, 131 FERC ¶ 61,253 (2010).
[84] *Id*.

are not present (as in the case of merchant projects), in which case the merchant developer must bear the financial risk. Based on the above, the Commission should recognize the similarities between Filing Parties' MVPs and merchant transmission facilities, and require any new class of MVPs to meet the same obligations as merchant facilities, as part of its final order in this proceeding.

5. States and Utilities That Do Not Need To Or Want To Rely On Remote Wind Resources Should Not Be Required To Subsidize The Costs Of Transmission Needed By Others To Access Those Resources.

The inherent unfairness of a broad socialization of the costs of transmission upgrades can be seen in two situations already present in the MISO region. First, some states have enacted laws that require renewable energy resources to be located within the state. Requiring customers in neighboring states to underwrite transmission projects used to facilitate the interconnection of in-state resources to satisfy in state renewable portfolio requirements rises to the level of taxation without representation. This would be analogous to a state deciding they need to construct a new highway to facilitate economic development, but rather than using road tolls to pay for the project, impose a vehicle license fee on drivers in <u>neighboring</u> states. The results in either instance fail to align the project beneficiaries with the project costs.

Such state laws exist within the MISO region. For example, Michigan Act 129 of 2008 requires, among other provisions, that a portion of the state's retail electricity sales be provided from renewable energy systems. Renewable energy systems must satisfy in-state locational requirements, with some limited exceptions:

> 460.1029 Renewable energy system location; requirements.
>
> Sec. 29.
>
> (1) Subject to subsection (2), a renewable energy system that is the source of renewable energy credits used to satisfy the renewable energy standards shall be either located outside of this state in the retail electric customer service territory

of any provider that is not an alternative electric supplier or located anywhere in this state. For the purposes of this subsection, a retail electric customer service territory shall be considered to be the territory recognized by the commission on January 1, 2008 and any expansion of retail electric customer service territory recognized by the commission after January 1, 2008 under 1939 PA 3, MCL 460.1 to 460.10cc. The commission may also expand a service territory for the purposes of this subsection if a lack of transmission lines limits the ability to obtain sufficient renewable energy from renewable energy systems that meet the location requirement of this subsection.

(2) The renewable energy system location requirements in subsection (1) do not apply if 1 or more of the following requirements are met:

(a) The renewable energy system is a wind energy conversion system and the electricity generated by the wind energy system, or the renewable energy credits associated with that electricity, is being purchased under a contract in effect on January 1, 2008. If the electricity and associated renewable energy credits purchased under such a contract are used by an electric provider to meet renewable energy requirements established after January 1, 2008 by the legislature of the state in which the wind energy conversion system is located, the electric provider may, for the purpose of meeting the renewable energy credit standard under this act, obtain, by any means authorized under section 27, up to the same number of replacement renewable energy credits from any other wind energy conversion systems located in that state. This subdivision shall not be utilized by an alternative electric supplier unless the alternative electric supplier was licensed in this state on January 1, 2008. Renewable energy credits from a renewable energy system under a contract with an alternative electric supplier under this subdivision shall not be used by another electric provider to meet its requirements under this part.

(b) The renewable energy system is a wind energy conversion system that was under construction or operational and owned by an electric provider on January 1, 2008. This subdivision shall not be utilized by an alternative electric supplier.

(c) The renewable energy system is a wind energy conversion system that includes multiple wind turbines, at least 1 of the wind turbines meets the location requirements of this section, and the remaining wind turbines are within 15 miles of a wind turbine that is part of that wind energy conversion system and that meets the location requirements of this section.

(d) Before January 1, 2008, an electric provider serving not more than 75,000 retail electric customers in this state filed an application for a certificate of authority for the renewable energy system with a state regulatory commission in another state that is also served by the electric provider. However, renewable energy credits shall not be granted under this subdivision for electricity generated using more than 10.0 megawatts of nameplate capacity of the renewable energy system.

(e) Electricity generated from the renewable energy system is sold by a not-for-profit entity located in Indiana or Wisconsin to a municipally-owned electric utility in this state or cooperative electric utility in this state under a contract in effect on January 1, 2008, and the electricity is not being used to meet another state's standard for renewable energy.

(f) Electricity generated from the renewable energy system is sold by a not-for-profit entity located in Ohio to a municipally-owned electric utility in this state under a contract approved by resolution of the governing body of the municipally-owned electric utility by January 1, 2008, and the electricity is not being used to meet another state's standard for renewable energy. However, renewable energy credits shall not be granted for electricity generated using more than 13.4 megawatts of nameplate capacity of the renewable energy system.

(g) All of the following requirements are met:

(i) The renewable energy system is a wind energy system, is interconnected to the electric provider's transmission system, and is located in a state in which the electric provider has service territory.

(ii) The electric provider competitively bid any contract for engineering, procurement, or construction of the renewable energy system, if the electric provider owns the renewable energy system, or for purchase of the renewable energy and associated renewable energy credits from the renewable energy system, if the provider does not own the renewable energy system, in a process open to renewable energy systems sited in this state.

(iii) The renewable energy credits from the renewable energy system are only used by that electric provider to meet the renewable energy standard.

(iv) The electric provider is not an alternative electric supplier.[85]

While it may be acceptable that Michigan may impose an in-state locational requirement for renewable energy systems that are necessary to satisfy the state's renewable portfolio requirements, it is unreasonable to utilize MISO's tariff as a vehicle for customers in other states to subsidize the costs associated with Michigan's in-state resource requirement.

Second, some utilities have already committed to incurring the necessary investments in transmission to meet all of their renewable portfolio obligations. For example, Minnesota Power recently petitioned for approval to purchase a 250 kV direct current transmission line running

[85] *See* MICH. COMP LAWS § 460.1029.

from Center, North Dakota to a substation near Duluth, Minnesota ("DC Line").[86] In the DC Line Petition, Minnesota Power stated its purpose of acquiring the DC Line was to transport energy generated by wind turbines built in North Dakota to meet the Minnesota renewable energy mandates.[87] As of 2009, Minnesota Power had procured about 50% of the anticipated renewable generating resources necessary to meet the Minnesota "25 by 2025" standard.[88] If acquisition of the DC Line were approved, Minnesota Power represented it would be able to fully comply with the Minnesota renewable energy standard by 2025 by building or leasing sufficient wind resources in North Dakota and transporting the energy generated by those wind resources to Minnesota ratepayers via the DC Line.[89] Ultimately, the DC Line Petition was approved as a reasonable and relatively low-cost method of taking the steps necessary to meet the Minnesota renewable energy standard.[90] Minnesota Power subsequently built the costs of acquiring the DC Line into its 2009 retail rate case.[91] That rate increase is presently pending approval by the Minnesota Public Utilities Commission.

This example demonstrates the fundamental unfairness of requiring all ratepayers to subsidize costs of transmission investment – the cost allocation proposal will unfairly charge

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[86] *In the Matter of Minnesota Power's Petition to Purchase Square Butte Cooperative's Transmission Assets and for Restructuring Power Purchase Agreements from Milton R. Young Unit 2 Generating Station*, Minnesota Public Utilities Commission Docket No. E-015/PA-09-526, Petition for Approval (May 14, 2009) ("DC Line Petition").
[87] *DC Line Petition*, pg. 21.
[88] *Id; see* also MINN. STAT. § 216B.1691 subd. 2a. ("each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota…so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated…(4) 2025 25%").
[89] *DC Line Petition,* pg. 21.
[90] *In the Matter of Minnesota Power's Petition to Purchase Square Butte Cooperative's Transmission Assets and for Restructuring Power Purchase Agreements from Milton R. Young Unit 2 Generating Station*, Minnesota Public Utilities Commission Docket No. E-015/PA-09-526, Order Granting Petition with Conditions (December 21, 2009).
[91] *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Minnesota Public Utilities Commission Docket No. E015/GR-09-1151 ("MP 2009 Rate Case"), Direct Testimony of Allan S. Rudeck, Jr., pg. 44 ("The test year rate base balance includes a total capital investment [for the DC Line facilities] of $81 million. In addition to the $72 million purchase, this amount includes $2.56 million for DC terminal upgrades to support an eventual 50 MW upgrade of the DC line by 2013, $1.19 million in acquisition costs booked in 2008, and $5.24 million for replacement of HVDC base system components."). The actual cost Minnesota Power seeks to recover has been slightly modified during the course of the rate case proceedings. *See MP 2009 Rate Case*, Administrative Law Judge's Findings of Fact, Conclusions, and Recommendation (August 17, 2010), ¶¶ 165-184.

Minnesota Power ratepayers with costs of transmission investment that are unnecessary for Minnesota Power to meet the Minnesota renewable energy standard. It also proves that the Filing Parties' cost allocation proposal is contrary to the longstanding principle of "beneficiary pays" cited above. Simply stated, states and utilities that do not need or want to rely on remote wind resources should not be required to subsidize the costs of transmission needed by others to access those resources.

6. The Proposed Criteria To Qualify Multi-Value Projects Would Inappropriately Shift Network Upgrade Costs Associated With Generator Interconnections To Load.

The Filing Parties make no secret that categorizing projects as MVPs would shift to load "significant" costs that are presently treated as interconnection costs**.** The root cause for this shifting of costs is discussed in the testimony of Eric Laverty:

> Q. WILL GENERATORS CONTINUE TO SEE THE HIGH NETWORK UPGRADE COSTS UNDER THIS PROPOSAL THAT MANY ARE SEEING NOW?
>
> A. No, at least not for most of them. The package of changes in this filing should significantly reduce, overall, the Network Upgrade costs faced by any individual Interconnection Customer, while also providing greater assurance that any remaining costs are appropriately borne by Interconnection Customers. <u>Generators locating in areas that benefit from MVPs will see much lower Network Upgrade costs than would be seen now, when they must fund what would otherwise be an MVP.</u> Conversely, generator interconnection requests made in areas that lack robust transmission infrastructure without proposed MVPs will drive the need for significant upgrades to the Transmission System and those generators, either alone or as a group, appropriately should bear those costs. But even in this case, the proposed revisions ensure that the costs will be properly shared among those Interconnection Customers, and not unduly burden the first movers.
>
> Q. PLEASE EXPLAIN WHY THE ADDITION OF THE SHARED NETWORK UPGRADE AND MULTI-VALUE PROJECT IS AN IMPROVEMENT TO THE CURRENT RULES
>
> A. Under the revisions proposed in this filing, the costs allocated to any particular Interconnection Customer will likely be reduced in many instances for two reasons. <u>First, Network Upgrades previously assigned to interconnecting</u>

> generators may now be designated as MVPs, which generators would not be required to fund. Second, Network Upgrades that are later found to benefit other interconnection customers will be designated as SNUs and the Interconnection Customer that originally funded such Network Upgrades would be eligible for contribution from other generators that share the benefit of a specific upgrade.

Laverty Testimony at 20-21 (emphasis added). This testimony demonstrates that the proposed cost allocation for MVPs would produce an underlying discriminatory subsidy to interconnecting generation that would render meaningless the Commission's policies that the costs of network upgrades not necessary "but for" an interconnecting generation resource be directly assigned to the interconnecting generator.[92]

a. The Experience With The Brookings 345 kV Line Demonstrates The "About-Face" On MISO's Views On What Qualifies As A Generation Interconnection Network Upgrade.

The history of MISO's views on the appropriate treatment of interconnection costs undermines the basis for MISO's claims in this proceeding. On August 13, 2009, MISO submitted an unexecuted Amended and Restated Generator Interconnection Agreement (Amended GIA) among the Midwest ISO, Northern States Power Company (NSP), as transmission owner; and Community Wind North LLC (Community Wind), as interconnection customer. MISO proposed, under Appendix A of the Amended GIA, to require Community Wind to share in the cost responsibility for Shared Ownership Common Use upgrades, including the Brookings Line, which is a 230-mile, 345-kV transmission line that will connect Brookings County, South Dakota, with eastern Minnesota ("Brookings Line").

Several other parties intervened in the case and argued that it was inappropriate to assign the costs of the Brooking Line to Community Wind and other potential interconnection

[92] *See, e.g., Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 694 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

customers. They argued that the Brookings Line was being developed as part of the CapX2020 initiative, which is designed to support the growing demand for electricity in Minnesota and the surrounding region and is, therefore, not a network upgrade necessary but for their interconnection.

The Commission accepted the Amended GIA conditioned upon on MISO modifying the Amended GIA to remove any reference to cost responsibility for the Brookings Line.[93] The October 9 Order recognized that MISO's tariff embodies the requirement that interconnecting customers bear responsibility for network upgrades that would not be necessary but for their interconnection.[94] The Commission found that MISO had failed to provide evidence demonstrating the allocation of the costs of the Brookings Line was reasonable. Although the Commission rejected that element of the Amended GIA, it did so without prejudice to MISO re-filing a proposal to allocate the costs of the Brookings Line with appropriate support.[95]

MISO sought rehearing of the October 9 Order arguing, among other things, that the Commission erred by failing to find that the results of a group study conducted in accordance with MISO's group study process, which identified the need for network upgrades caused by the group of projects, was sufficient evidence that the upgrades would satisfy the "but for" test as it applies to the study group as a whole rather than to any single member of the study group.

The Commission denied MISO's request for rehearing but clarified its intent:

> We clarify that we view the "but for" standard, in the context of Midwest ISO's Tariff, as a cost allocation principle that limits the cost responsibility of an interconnection customer or a group of interconnection customers to the cost of the upgrades that would not be necessary but for the interconnection of the customer or reasonably constituted group of customers. The Tariff adopts the language of the *pro forma* Large Generator Interconnection Agreement's (LGIA) definition of network upgrades and, like the *pro forma* LGIA, uses the "but for"

[93] *Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,019 (October 9, 2009) ("October 9 Order").
[94] October 9 Order at P 23.
[95] Id at P 24.

standard. While Midwest ISO is correct in stating that it can propose variations from the Commission's *pro forma* LGIP as an independent Transmission Provider, we disagree with Midwest ISO's interpretation of section 8.4. To the extent that Midwest ISO suggests that the presence of the terms "System Planning and Analysis Review" and "Good Utility Practice" mean that the word "required" as it is used in section 8.4 and in the definition of network upgrades should be interpreted such that Midwest ISO's Tariff does not include the "but for" standard, we disagree. We note that in the very same proceeding that Midwest ISO proposed and the Commission accepted the addition of the term "required" to the "Scope of Interconnection Facilities Study" section (then section 8.2), Midwest ISO acknowledged that it was adopting the Commission's default pricing policy, including the "but for" standard for the purpose of the definition of network upgrades. Further, we note the similarity between section 8.4 of Midwest ISO's Generator Interconnection Procedures and section 8.2 of the *pro forma* Generator Interconnection Procedures. Despite the presence of "Good Utility Practice" in section 8.2 of the *pro forma* Generator Interconnection Procedures, the Commission never suggested that section 8.2's reference to "Good Utility Practice" should be interpreted as expanding the meaning of "required" for the purpose of the definition of network upgrades. In other words, interconnection customers in Midwest ISO are required to fund the cost of network upgrades that would not have been needed but for their interconnection.

We clarify that this language does not limit Midwest ISO or its transmission owners to the least-cost option available to interconnect a generator or group of generators. The Tariff affords Midwest ISO some discretion when determining what facilities should be built in order to accommodate the interconnection of a project or group of projects. In particular, sections 7.1 and 8.1 of the Generator Interconnection Procedures recognize that Midwest ISO should use its study process to identify network upgrades that: (1) ensure that an interconnection customer or group of interconnection customers can reliably connect to the transmission system; and (2) ensure that the network upgrades chosen promote efficiency. We do not doubt that a range of improvements could achieve these results. In addition, we have previously recognized that Midwest ISO's use of group studies allows it to focus on the needs of both the relevant interconnection customers and the overall system.

Thus, Midwest ISO may determine through its study process that a large upgrade, such as the Brookings Line, should be built because it will both accommodate the interconnection of a group of projects and address other system-wide needs. However, the cost responsibility of a group of interconnection customers remains limited to the cost of the facilities that would not be needed but for the interconnection of the group. In this case, the evidence submitted indicated that the Brookings Line was needed for more than interconnection, but the cost allocation language in the Amended GIA was not sufficient to limit Community Wind's (or Group 5's) cost responsibility for the Brookings Line such that they were funding only the cost of upgrades that would not have been necessary but for their interconnection. In other words, the evidence submitted does not support

> allocation of 100 percent of the costs of the Brookings Line to the Group 5 projects. Because the Initial Order's direction to remove the unsupported language relating to any cost responsibility for the Brookings Line could have been read to imply that the "but for" standard determines the network upgrades that can be built to accommodate an interconnection customer or group of interconnection customers, rather than is solely related to cost allocation, we will clarify the Initial Order and require a further compliance filing, as discussed below.[96]

Thus, although the Commission rejected allocating the entire cost of the Brookings Line to Community Wind and other generation projects in the interconnection queue, it left open the possibility that a portion of the costs of the Brookings Line could be allocated to these generation projects, commensurate with that portion of the upgrade that would not be necessary but for their interconnection.

In its compliance filing in response to the May 20, 2010 Rehearing Order, MISO modified the Amended GIA as directed by the Commission to incorporate the following terms:

> Interconnection Customer shares in the cost responsibility for one or more Common Use Upgrades and/or Shared Ownership Common Use Upgrades that would not have been necessary but for the interconnection of Interconnection Customer and other Group 5 Generators. Such Common Use Upgrade(s) and/or Shared Ownership Common Use Upgrades are to be identified through restudy pursuant to the Commission's May 20, 2010 order in Docket No. ER09-1581 (131 FERC 61.165 (2010)), which may include responsibility for an appropriate portion of the new Brookings County Twin Cities 345 kV transmission line and related transmission substation upgrades ("Brookings County 345 kV Line"). Group 5 Generators' obligations to simultaneously secure and fund such Common Use Upgrades and/or Shared Ownership Common Use Upgrades will be governed by separate, future Multi-Party Facility Construction Agreement(s). Compliance Filing of Midwest Independent Transmission System Operator, Inc., regarding the unexecuted G586 Amended and Restated Generator Interconnection Agreement in FERC Docket Nos. ER09-1581-004, Amended and Restated Generator Interconnection Agreement, Original Sheet No. 90.

MISO's June 18, 2010 compliance filing in response to the May 20, 2010 Rehearing Order is still pending before the Commission.

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[96] *Midwest Independent Transmission System Operator, Inc.*, 131 FERC 61,165 at PP 20-23 (May 20, 2010) ("May 20, 2010 Rehearing Order").

Notwithstanding the provisions in the Amended and Restated Generator Interconnection Agreement pending at the Commission, in this proceeding, the Filing Parties have included the very same Brookings Line as an MVP starter project that would have its entire cost allocated to load, with no cost responsibility assigned to interconnection customers, if the Application is accepted by the Commission. MISO's flip-flop on the treatment of interconnection costs is not reasonable and results in a discriminatory and unlawful subsidy to new generation resources.[97]

b. Multi-Value Projects Approved To Facilitate Additional Wind Generation In Off-Peak Hours Demonstrates That The Projects Are Not Necessary "But For" The Interconnection Of Wind Resources.

The Filing Parties' witness Curran testifies that the anticipated need for transmission projects likely to be classified as MVP is additional transfer capacity for economy energy transfers.[98] Ms. Curran indicates this need arises due to fact that only a small percentage of wind generation is expected to occur during on-peak periods.[99] Ms. Curran's testimony demonstrates that these types of MVPs are not necessary but for the interconnection of wind generation.

Moreover, transmission planning seeks to ensure that sufficient capacity exists to reliably serve customer's load at the time of peak demand. Once sufficient transmission capacity exists to serve peak demand, customers (load) do not require additional transmission capacity.[100] Because these transmission facilities would not be necessary "but for" wind interconnection facilities, and are not needed for other reasons, the costs of the facilities should be allocated consistent with "but for" cost allocation.

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97 As a result of no longer directly assigning the costs of network upgrades that are necessary as a result in interconnection to new generation resources, new generation resources would be subsidized *vis-a-vis* existing generation resources also.

98 Curran Testimony at 12.

99 Id.

100 If additional transmission investment will lower the overall cost of electricity as a result of economy energy transfers such investments should be undertaken and customers should be willing to fund such investments. MISO's existing tariff already has mechanisms in place (and that MISO is proposing to maintain) to provide for regional cost sharing of these types of transmission projects if it can be demonstrated that the project meets a Commission approved benefits-to-cost threshold. Such projects are classified as Regionally Beneficial Projects under MISO's current tariff.

B. The Filing Parties Have Not Demonstrated That Their Energy-Based Allocation Is Consistent With Cost Causation And Beneficiaries Pay, Or Is Otherwise Required Or Is Just And Reasonable.

As discussed *supra*, and in the Dauphinais Affidavit, the Filing Parties have unreasonably proposed regional cost sharing for MVPs through an energy-based allocation methodology. MVPs that met Criterion 1 would not necessarily address reliability issues or provide economic benefits in excess of costs, but would be undertaken to facilitate public policy requirements, primarily renewable portfolio obligations.

Criterion 1 MVPs are designed to facilitate the development of renewable generation required to satisfy public policy requirements by removing cost barriers to integrating renewable generation resources remotely from load.[101] These projects are <u>not</u> driven by energy consumption or demand, but rather by the nature of the associated renewable generation being concentrated in particular remote areas of the MISO. The transmission projects must be sized to accommodate the peak output from all of the nearby renewable resources, because their maximum output, which is dependent upon wind speed, will be largely coincident with one another. In these circumstances, it is not appropriate to allocate the cost of MVPs that satisfy Criterion 1 to transmission customers on either the basis of energy consumption or demand. Rather, costs should be allocated to the generators based on the respective nameplate capacity of the geographically concentrated wind generation facilities that would benefit from the transmission.

The costs of such MVP projects should be directly assigned to the interconnecting generation facilities, recognizing that the MVP would not be necessary but for the interconnecting generation resources. Alternatively, states or utilities with renewable portfolio mandates could choose to commit to funding MVP during an open season or a joint arrangement,

[101] Curran Testimony at 5.

consistent with the process employed for other such facilities. Either approach assures that the costs of such projects are associated with the generation facilities that cause them, and that (i) these public policy costs are transparent by not being mixed in with project costs that are related to reliability or economics; (ii) concentrated, remotely located renewable generation is not subsidized at the expense of distributed renewable generation; and (iii) price signals are not sent to load that discourage usage during off-peak periods rather than on-peak periods.

The Filing Parties' proposal regarding Criterion 2 MVPs appears to be an attempted end run around the benefit to cost ratio that is currently required for regional cost sharing of regionally beneficial projects (which the Filing Parties propose to rename as market efficiency projects) under MISO's currently approved tariff. That tariff provides for regional cost sharing of projects that satisfy a cost benefit threshold. Specifically, 20% of the project cost for regionally beneficial projects with a voltage class of 345 kV or higher and a project cost of $5 million or more (or, alternatively, 5% or more of the transmission owner's net plant) are allocated on a system-wide basis to all transmission customers, with the remaining 80% of the cost being allocated to transmission customers in designated pricing zones in accordance with a line outage distribution factor ("LODF") developed by MISO. The allocated costs are recovered from transmission customers through transmission rates based on monthly coincident peaks (for network transmission service) and reserved capacity (for point-to-point transmission service).

A Criterion 2 MVP is required to have a higher minimum cost than a market efficiency project ($20 million versus $5 million). However, the minimum voltage and benefit-to-cost ratio requirements for Criterion 2 MVPs are more lenient than those for market efficiency projects. Moreover, the Filing Parties' proposal would classify any market efficiency project that meets any of the three MVP criteria as an MVP rather than a market efficiency project. As such, on a going forward basis, only projects that qualify as market efficiency projects with projected costs between $5 million and $20 million, and the project is less than 5% of the transmission owner's net plant, would be classified as market efficiency projects.

The Filing Parties' proposal inappropriately and unnecessarily uplifts 100% of the cost of Criterion 2 MVPs that would otherwise be classified as market efficiency projects to all MISO transmission customers regardless of the economic benefits or detriments that these customers will experience. The proposal also fails to recognize these transmission projects are driven by economics, and not by total energy consumption. To the extent the current minimum benefit-to-cost ratio requirement or 345 kV facility voltage requirements for market efficiency projects are viewed as too high a hurdle, it is more appropriate to modify the minimum requirements to qualify for a market efficiency project, rather than lumping market efficiency projects together with projects that are for other purposes (e.g., to meet public policy renewable energy requirements) and effectively changing the cost allocation and rate design for market efficiency projects.

Criterion 3 MVPs are projects that would be justified alone on a reliability basis, but also provide economic value over multiple pricing zones. The Filing Parties' proposal would reclassify new projects that would currently qualify as baseline reliability as MVPs if they meet any of the three MVP criteria. Reliability justified network upgrades are generally driven by system peak demand rather than energy usage. Therefore, it is not appropriate to recover the costs of such projects based upon energy usage. The costs of transmission upgrades under taken primarily to address reliability issues should be based on monthly coincident peak demand for network transmission customers and Reserved Capacity for point-to-point transmission customers.

1. The Filing Parties Have Not Demonstrated That the Estimated Benefits Of MVPs Are Dependent Upon Energy Use.

The Filing Parties have not provided sufficient evidence to demonstrate the estimated benefits of MVPs are dependent upon energy usage. Ms. Curran testifies that the Filing Parties' proposal properly aligns costs to beneficiaries because costs will vary based upon energy usage.[102] Ms. Curran also testifies that a usage-based charge (i.e., per MWh) is warranted under the MVP cost allocation proposal because energy flows and corresponding benefits from MVPs will occur in all hours of the year, not just during peak demand hours.[103] It is no more effective to measure system use based upon volumetric consumption than it is to measure use based on monthly coincident peak demands and reserved capacity. A customer's energy usage and coincident peak demands may change over time. However, in the later instance, a customer's coincident peak demand is a good proxy for its share of the total system use. Further, the Filing Parties have not demonstrated a nexus between the benefits received from MVP projects and total energy usage.

The benefits from MVPs may occur in different hours of the year depending on whether a project is driven by reliability, economics or renewable energy mandates, but that does not mean the benefits are evenly distributed over all hours of the year. Depending on the particular project in question, benefits could be concentrated at the time of system peak demand. However, the benefits could also be concentrated at the time of peak wind generation energy production in a particular area, or during off-peak hours, or on-peak hours or shoulder hours.

[102] Curran Testimony at 10.
[103] Id at 12.

2. A MWh-Based Cost Allocation Would Disproportionately Impact Higher Load Factor Customers.

The Filing Parties' proposed cost allocation would disproportionately impact higher load factor customers and unfairly benefit lower-load factor customers. As explained through an example by Mr. Dauphinais in his Affidavit, moving from a demand-based allocator to an energy-based allocator would impose higher costs on those customers that are the most efficient users of the system and, conversely, lower costs on those customers that are the less efficient users of the system.[104] The Filing Parties do not acknowledge, much less address, this adverse impact. It is also worth observing that higher load factor customers tend to be large manufacturing and mining operations in the Midwest that are subject to severe economic pressure. The Filing Parties' proposal would cause harm to this class of customers and, thus, directly undermine state and federal efforts to restore the economic health of the region. These disproportionate and subversive impacts of a MWh-based cost allocation require a finding that the proposal is not just and reasonable.

C. Several Significant Modifications Must Be Made To The Filing Parties' Proposal To Make It Just And Reasonable.

For the reasons discussed herein, the Filing Parties have failed to demonstrate that their MVP proposal is just and reasonable. Several significant modifications to the Filing Parties' proposal are required in order to produce a just and reasonable result.

1. The Filing Parties' Proposal Must Align With A Beneficiary Pays Approach.

As discussed supra, Industrial Customers do not believe the Commission should approve the Filing Parties' MVP tariff language that would vest MISO with broad discretion as to what projects can qualify as MVPs. The Commission should only vest MISO with the authority to approve transmission projects that resolve known reliability issues, or are projected to provide

[104] *See* Dauphinais Affidavit at PP 25-35.

economic benefits in excess of Commission-approved threshold levels in order to qualify as Regionally Beneficial Projects under MISO's existing tariff. Speculative transmission projects, which Criterion 1 MVPs are by nature, should be subject to an open season process to gain customer commitments with the project cost and risk being borne by the developer of the transmission project.[105]

However, irrespective of whether the Commission agrees with Industrial Customers on these issues, the Filing Parties' proposed cost allocation for MVPs should not be approved, as it fails to align the allocation of costs with beneficiaries. The Commission should require the Filing Parties to apply the currently applicable rules for Regionally Beneficial Projects to Criterion 2 MVPs. Twenty percent (20%) of the project cost of the MVPs should be allocated on a system-wide basis to all transmission customers and recovered through a system-wide rate. The remaining 80% of the costs of MVPs should be allocated on a sub region-wide basis to all transmission customers in each of the three defined planning sub-regions. The allocated cost to each planning sub-region shall be based on the relative benefit determined for each planning sub-region that has a positive present value of annual benefits over the evaluation period using the methodology for project benefit determination. These allocated costs should continue to be recovered through transmission rates based on monthly coincident peak demand and Reserved Capacity. Criterion 3 MVPs should be subject to the current allocation rules for BRPs and the allocated costs for such MVPs should also continue to be recovered through transmission rates based on monthly coincident peak demand and Reserved Capacity.

Finally, in the event a project provides for reliability, economic, and public policy needs:

[105] Transmission customers would commit to pay transmission rate for contract terms to pay for the project cost. To the extent that customer commitments were not sufficient to pay for their entire project costs the project developer would assume the risk.

- the portion of the project equal to the minimum cost that would need to be incurred to meet the reliability need should be allocated as a BRP,
- the minimum incremental cost necessary to address the economic need should be allocated as a regionally beneficial project, and
- any remaining incremental cost necessary to meet the renewable generation public policy need should be treated in the same manner as costs of a merchant transmission project are treated.

2. MISO's Tariff Must Incorporate Periodic Adjustment Of Cost Allocation To Reflect Changes In Power Flows When Appropriate.

Additionally, the Commission should require MISO's tariff to incorporate language that would require periodic adjustment to the allocation of costs associated with MVPs, when changes in power flows are materially different from those initially assumed when the project is approved. Power flows change as loads grow or decline, as new generators are added to the grid (or retired), and as a result of new or upgraded transmission infrastructure. The changes in flows cannot always be anticipated and therefore a flow-based transmission cost allocation methodology should require and enable recalculations when appropriate on a periodic basis. This does not change the amount of total costs that are recovered and, therefore, should add no regulatory uncertainty to cost recovery. Only the mix of, and allocations to, beneficiaries change. Industrial Customers do not recommend that continued alignment of the impacts and beneficiaries from changing power flows be left to chance. Rather, the Commission should require MISO to demonstrate in future compliance filings, at least once every five years, that application of the cost allocation methodology to each project continues to align beneficiaries with cost responsibility.

D. An Evidentiary Hearing Would Facilitate Development Of The Record.

The Filing and the various protests that are likely to be filed raise, and will raise, genuine issues of material fact. If the Commission is not inclined to summarily deny the relief requested by the Filing Parties or summarily direct modifications as proposed above by Industrial Customers, then it should set the Filing for evidentiary hearing and allow the parties to conduct full discovery.

III. <u>CONCLUSION</u>

WHEREFORE, Industrial Customers respectfully request that the Commission find that the Filing Parties have not demonstrated that the Filing is just, reasonable, and not unduly discriminatory. Alternatively, and if the Commission is inclined to accept some version of the Filing, the Commission should require the changes specified in Section II.C., *supra*.

Respectfully submitted,

McNEES WALLACE & NURICK LLC

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Counsel to the Wisconsin Industrial Energy Group

Dated: September 10, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Protest of the Industrial Customers *via* electronic transmission, hand-delivery or ordinary U.S. mail, postage prepaid, upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 10th day of September, 2010.

/ s / Robert A. Weishaar, Jr.

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Counsel to the Coalition of Midwest Transmission Customers

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C.

Midwest Independent Transmission System Operator, Inc.	)))	Docket No. ER10-1791-000

AFFIDAVIT OF JAMES R. DAUPHINAIS
ON BEHALF OF
INDUSTRIAL CUSTOMERS

I, James R. Dauphinais, being duly sworn, depose and state as follows:

INTRODUCTION

1. I am a Principal of Brubaker & Associates, Inc. ("BAI"),16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. I have been affiliated with BAI since June of 1997. BAI is a consulting firm that specializes in the field of public utility regulation. Prior to my affiliation with BAI, I was a Senior Engineer in the Transmission Planning Department of the Northeast Utilities Service Company ("NU"). During my twelve and one-half year tenure at NU, I was responsible for conducting thermal, voltage and stability analysis on NU's transmission system to support planning and operating decisions. Beginning in 1995, I also became involved at NU with open access transmission issues. During this period I was responsible for the day-to-day administration of the NU Open Access Transmission Tariff ("OATT"), creation of NU's pre-Order No. 889 transmission electronic bulletin board system and coordination of NU's OATT filings just prior to and after the Federal Energy Regulatory Commission's ("FERC" or "Commission") issuance of Order No. 888. I was also responsible for spearheading the implementation of NU's Open Access Same-Time Information System ("OASIS") and NU's Standard of Conduct under Order No. 889. During this time I was a participant on behalf of NU on the FERC's "What" Working Group on Real-Time Information Networks, served as Vice Chairman of the NEPOOL OASIS Working Group and Co-chair of the Joint Transmission Service Information Network ("JTSIN") Functional Process Committee. I also participated briefly in the North American Electric Reliability Council-facilitated Commercial Practices Working Group. Since my affiliation with BAI, I have been involved in a wide variety of energy, economic and regulatory issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, fuel adjustment clauses, generation interconnection, interruptible rates, market power, market price forecasting, market structure, power procurement, prudency, regional transmission organizations, resource planning, retail open access, standby rates, transmission access, transmission losses, transmission planning and transmission rates. I have filed testimony and/or sworn affidavits before the Federal Energy Regulatory Commission ("FERC" or "Commission") in Consumers Energy Company, Docket No. OA96-77-000; Midwest Independent

Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; SkyGen Energy, LLC v. Southern Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Illinois Power Company, et al., Docket No. EC03-30-000, et al.; Entergy Services, Inc., Docket No. ER04-699-000; and Entergy Services, Inc., Docket No. EL05-52-000. I have also presented comments before the Commission in Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003 and Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000. I have also filed testimony before many state utility regulatory commissions. My professional experience is further detailed in Appendix A to this affidavit.

2. I have been retained by Industrial Customers to review the Midwest Independent Transmission System Operator, Inc ("MISO") proposal in Docket No. ER10-1791-000 to allocate the cost of transmission projects classified as Multi-Value Projects ("MVP") on a total energy usage basis rather than on the basis of monthly coincident peak demand and Reserved Capacity. The primary purpose of my affidavit is to attest to my evaluation of the reasonableness of MISO's proposal to allocate the cost of MVP projects to load within the MISO footprint, exports out of the MISO footprint and transmission service across the MISO footprint on a per MWh (i.e., total energy usage) basis. I have reviewed the cover letter, tariff pages and the testimony that MISO has filed in this proceeding. I have also reviewed several documents that have been cited by MISO's witnesses in their respective testimonies, but which were not filed in this proceeding. I conclude that MISO's proposal to allocate the cost of MVPs to load, exports and wheeling of power across the MISO footprint is not just and reasonable because it is not consistent with cost causation, subsidizes centralized wind generation and is not even roughly commensurate with the benefits that would be received from such projects. I also conclude that the proposed use of transmission rates based on total energy usage rather than transmission rates based on monthly coincident peak demand, Reserved Capacity and the nameplate capacity of wind generation being accessed would on a going forward basis unduly and unnecessarily shift transmission investment costs from low load factor customers to high load factor customers. Finally, I conclude that MISO has not demonstrated that transmission rates based on total energy usage are any more effective at tracking changes in the beneficiaries of transmission projects than transmission rates based on monthly coincident peak demand, Reserved Capacity and the nameplate capacity of wind generation being accessed.

BACKGROUND

3. MISO currently has regional cost sharing for Baseline Reliability Projects ("BRP" or "RECB I Projects") and Market Efficiency Projects ("MEP" or "RECB II Projects", formerly known as "Regionally Beneficial Projects").

4. BRPs are Network Upgrades required to ensure that the MISO transmission system remains in compliance with applicable national and regional reliability standards. They include projects operating at 100 kV or higher voltage that are needed to maintain reliability while accommodating the ongoing needs of existing transmission customers. Under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff"), the costs of BRPs meeting certain criteria are eligible to receive

partial regional cost sharing. Specifically, 20% of the project cost for BRPs with a voltage class of 345 kV or higher and which have a project cost of $5 million or more (or, alternatively, 5% or more of the Transmission Owner's net plant) is allocated on a system-wide basis to all transmission customers with the remaining 80% of the cost being allocated to transmission customers in designated pricing zones in accordance with a Line Outage Distribution Factor ("LODF") Table developed by MISO. Both of these cost allocations are recovered from transmission customers through transmission rates based on monthly coincident peak demand (for Network Transmission Service) and Reserved Capacity (for Point-to-Point Transmission Service). (MISO Tariff at 3456 – 3457)

5. MEPs are Network Upgrades that provide an economic benefit and meet certain minimum standards. They include projects that involve facilities with a voltage class of 345 kV or higher, cost more than $5 million, meet certain minimum benefit-to-cost ratio requirements and are not determined to be (i) a BRP or (ii) a project providing new transmission access. If a project meets these standards, then 20% of its cost is allocated on a system-wide basis to all transmission customers and 80% of its cost is allocated to transmission customers on a sub-regional basis based on a beneficiary analysis. Under that beneficiary analysis, cost is allocated to each of the three MISO subregions (West, Central and East) based on the relative benefit determined for each subregion that is projected to have a positive present value of annual benefits over the evaluation period. Both of these cost allocations, just like the cost allocations for BRPs, are recovered from transmission customers through transmission rates based on monthly coincident peak demand and Reserved Capacity. (MISO Tariff at 3443 – 3451 and 3475 – 3480)

MISO MVP PROPOSAL

6. In this proceeding, the MISO proposes regional cost sharing for a new third group of projects called MVPs. MVPs would be transmission projects that involve facilities with a voltage class of 100 kV or higher, have a cost of $20 million or more (or, alternatively, 5% or more of the constructing transmission owner's net plant) and are not driven solely by either (i) an interconnection request or (ii) a transmission service request. In addition, to be an MVP, the project would be required to meet at least one of the following three criteria:

a. Criterion 1 - The project must be developed through the transmission expansion planning process for the purpose of enabling the transmission system to deliver energy reliably and economically support documented energy policy mandates or laws that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade; and/or

b. Criterion 2 - The project must provide multiple types of economic value across multiple pricing zones with a total project benefit-to-cost ratio of 1.0 or higher, as defined in Section II.C.6 of Attachment FF [of the MISO Tariff]. In conducting the benefit-to-cost analysis, the reduction of production costs and the associated reduction of locational marginal prices ("LMP") resulting from a transmission congestion relief project are not additive and are considered a single type of economic value; and/or

c. Criterion 3 - The project must address at least one Transmission Issue associated with a projected violation of a North American Electric Reliability Corporation ("NERC") or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. In this case, the project must generate total financially quantifiable benefits in excess of the total project costs based on financial benefits and project costs, as defined in Section II.C.6 of Attachment FF [of the MISO Tariff].

Finally, any project that meets the requirements to be an MVP and would otherwise qualify BRP or MEP would be classified as a MVP.

(MISO's proposed Tariff sheets at Original Sheet Nos. 3451 – 3451C and Filing Letter at 21).

7. MISO proposes to allocate 100% of the cost of MVPs to all transmission customers on a system-wide basis and recover that allocation from transmission customers under a transmission rate based on total energy usage rather than transmission rates based on monthly coincident peak demand and Reserved Capacity. The energy usage-based charge for MVPs would be recovered from all load within the MISO footprint, all exports of energy from the MISO footprint and all wheels of energy across the MISO footprint. Unlike for other MISO transmission service rates, transmission service that sinks in the PJM footprint would be subject to the MVP transmission service charge. (Filing Letter at 24-26).

8. Despite months of consultation with stakeholders and a significant investment in resources by the MISO Staff, the MVP proposal unfortunately amounts to little more than an involuntary pact to cast a wide net around proposed transmission projects and then uplift the cost for those projects to all MISO transmission customers on a per kWh basis. The proposal would act as an end-run around the existing BRP and MEP regional cost sharing provisions. It would require all transmission customers to bear the transmission cost burden of state-imposed public policy requirements related to renewable generation regardless of the degree to which those transmission customers are actually subject to those requirements. Finally, it would unreasonably shift transmission costs from low load factor customers to high load factor customers. It is not a proposal that allocates costs in a manner even roughly commensurate with the receipt of benefits.

CRITERION 1 MVPS

9. Criterion 1 MVPs are truly generation interconnection and transmission service projects designed to move power from areas where new concentrations of wind generation has already been or is expected to be interconnected. These projects are <u>not</u> driven by total energy consumption or system-wide demand, but rather by the nature of the associated wind generation being concentrated in particular remote areas of the MISO (e.g., particular areas of the Great Plains, the Michigan Thumb area, etc.) and the high level of coincidence of peak energy production by the wind generators within each of those remote areas.

10. Criterion 1 MVPs are ultimately being justified by public policy requirements for renewable generation -- not the economic or reliability needs of load. Those renewable generation public policy requirements vary significantly by state and not all MISO transmission customers are subject to those requirements. For example, Indiana currently does not have a renewable portfolio standard and Michigan's standard (Michigan Act 129 of 2008) relies upon in-state renewable resources.

11. If a Criterion 1 MVP is not necessary "but for" generation interconnection requests, the Commission's policies require the costs of such projects be initially funded by the interconnecting generators subject to the provisions of Order No. 2003. The cost for other MVPs that fall into Criterion 1 are not appropriately allocated to transmission customers on either the basis of total energy consumption or monthly coincident peak demand. Rather, since the need for these transmission projects is driven by forecasted peak energy production in the remote areas where the associated wind generation is being located and peak energy production by the individual wind generators within each of those areas is highly coincident, the cost of these projects is best allocated on the basis of the nameplate capacity of the wind generation facilities that are associated with these projects.

12. This nameplate capacity cost allocation method could be applied as a demand charge on the wind generators associated with these projects. Alternatively, groups of states or utilities with renewable purchase mandates could join together to jointly pursue these projects and allocate the costs among themselves based on the nameplate capacity amount of wind generation each participant is choosing to access. Either approach assures the costs of these projects are associated with the generation facilities that cause them such that (i) these public policy costs are transparent by not being mixed in with project costs that are related to reliability or economics; (ii) concentrated, remotely located renewable generation is not subsidized at the expense of distributed renewable generation; and (iii) price signals are not sent to load that discourages usage during off-peak periods rather than on-peak periods. Furthermore, the latter approach can already be pursued under MISO's Tariff with no modifications.

13. If the Commission were to conclude it is inappropriate to allocate these costs to generators or, alternatively, trust in the formation of groups of utilities and/or states to sponsor these projects, it would still not be appropriate to allocate the costs of these projects to all MISO transmission customers on the basis of total energy usage. If the Commission permits MISO to approve MVPs that meet only Criterion 1, any costs associated with Criterion 1 projects should be allocated only to those transmission customers that are specifically required to meet the public policy renewable generation requirements. Further, the costs should be allocated in proportion to the need caused by those requirements that results in the transmission projects. For the reasons I have noted, this should be based on allocating costs to those transmission customers on the basis of the amount of nameplate wind generation capacity being accessed.

CRITERION 2 MVPS

14. Criterion 2 MVPs are projects that would qualify as MEPs under current MISO tariff if their respective benefit-to-cost ratios were higher than projected and/or if they involved facilities 345 kV or higher in voltage. As I have noted, MEPs are currently allocated between the three MISO subregions on the basis of the projected cost savings

provided to each and recovered from transmission customers within each subregion through transmission rates based on monthly coincident peak demand and Reserved Capacity.

15. The motive behind the inclusion of Criterion 2 projects as MVPs appears to be an attempted end run around the current minimum benefit-to-cost ratio and voltage requirements for MEPs. While a Criterion 2 MVP potentially needs to have a higher minimum cost than a MEP ($20 million versus $5 million), the minimum voltage and benefit-to-cost ratio requirements for Criterion 2 MVPs are more lenient than that for MEPs. Moreover, MISO's proposal would have all MEPs that meet any of the three MVP criteria be designated as MVPs rather than MEPs. As such, it appears that on a going forward basis under the MISO proposal only projects that qualify as MEPs that fall between $5 million and $20 million in cost, where the project is less than 5% of the transmission owner's net plant, would be classified as MEPs.

16. The MVP proposal inappropriately and unnecessarily uplifts 100% of the cost of MEPs (and other projects that would be MEPs if they involved 345 kV or higher level facilities and/or had a higher projected benefit-to-cost ratio) to all MISO transmission customers regardless of the economic benefits or detriments that are projected for each of those transmission customers. It also fails to recognize that these transmission projects are driven by economics, not by total energy consumption, and often amount to accelerations of projects that will later be needed for reliability purposes. To the extent the current minimum benefit-to-cost ratio or 345 kV facility voltage requirements for MEPs are too high of a hurdle, this is best addressed by modifying the minimum requirements for MEPs, not by lumping these projects in with projects that are for other purposes (e.g., to meet renewable generation public policy requirements) and changing the rate design for these projects from one based on monthly coincident peak demand and Reserved Capacity to one based on total energy consumption.

CRITERION 3 MVPs

17. Criterion 3 MVPs are projects that would be justified alone on a reliability basis, but also provide economic value over multiple pricing zones. Criterion 3 would reclassify new projects that would currently qualify as BRPs as MVPs.

18. MISO's proposal would inappropriately change the cost allocation of projects needed for reliability from the current 20% system-wide / 80% LODF Table-based allocation for BRPs eligible for regional cost sharing and 100% transmission owner allocation for BRPs not eligible for regional cost sharing to a system-wide uplift of these costs on the basis that these projects also provide an economic benefit over multiple pricing zones. It would also inappropriately change the recovery of these costs from transmission rates based on monthly coincident peak demand and Reserved Capacity to transmission rates based on total energy usage.

19. Reliability justified network upgrades are generally, with few exceptions, driven by system peak demand not energy usage. Furthermore, as I have noted, to the extent an economic need is driving additional costs for a project in question, such economic upgrade costs are not being driven by total energy consumption, and often amount to accelerations of projects that will later be needed for reliability purposes.

20. If there is an issue with the current 345 kV minimum voltage requirement being too high for BRPs or the current percentage split between regional and LODF cost sharing, that can be addressed by revisiting the BRP provisions. It is not necessary or appropriate to lump such projects into the same bucket as transmission upgrades justified for other reasons and then allocate their costs to all MISO transmission customers on the basis of total energy usage.

COST ALLOCATION WHEN MORE THAN ONE MVP CRITERION IS MET

21. While it is true that some transmission projects could simultaneously meet two or more of the three of the MVP criteria, that is not a reasonable basis for the cost allocation to default to the least common denominator of a total energy usage based uplift of the project cost to all load, exports and wheel-throughs in the MISO. If a project is justifiable, it should be possible to determine a reasonable way for cost allocation purposes to split it between the renewable generation public policy need, the market efficiency need and the base reliability need, by applying hierarchies to a “but for” test.

22. For example, if a project is justifiable alone based on a reliability need, it is irrelevant whether the project also provides a net economic benefit or enables access to remotely located renewable generation because the project would be pursued for reliability regardless of those other coincidental benefits. Similarly, if a project cannot be justified based on a reliability need, but can be justified alone on the basis of net economic benefit, then it is irrelevant whether that project also enables access to remotely located renewable generation because the projects would be pursued for economic reasons regardless of the coincidental benefit of providing access to remotely located renewable generation.

23. Furthermore, if a project will meet a reliability need, but cannot meet an economic need without incremental additions, the portion of the cost of the project equal to the minimum cost that would need to be incurred to just meet the reliability need can be allocated as a BRP and the incremental cost necessary to enable the economic benefit could be allocated as a MEP.

24. This concept could be expanded further. For example, if a project could partially be justified by reliability, partially by economics and partially by a public policy need to access renewable generation, the portion of the cost of the project equal to the minimum cost that would need to be incurred to address the reliability issue would be allocated as a BRP, the minimum incremental cost on top of that necessary to provide the needed economic benefit would be allocated as a MEP and the remaining cost would be allocated as a project needed to meet renewable generation public policy requirements.

OTHER ISSUES RELATED TO MISO’S PROPOSED ENERGY USAGE (MWH) RATE FOR MVPS

25. MISO has projected approximately $4.6 billion of new transmission investment in the near term that may qualify as MVPs (Tab J of the MISO Filing). In addition, if the MISO’s Regional Generation Outlet Study (“RGOS”) projects are fully built out, there cost could run to approximately $16 to $20 billion in 2010 dollars and may largely qualify

as MVP investment ("Regional Generation Outlet Study (RGOS)", MISO Staff Presentation to the Planning Advisory Committee, July 21, 2010).

26. MISO's proposal to use transmission rates based on the total energy usage by transmission customers rather than monthly coincident peak demand and Reserved Capacity would shift a large portion of these future transmission investments from low load factor customers to high load factor customers.

27. For example, MISO reported in its calendar year 2009 FERC 714 filing that it had in 2009 a total net energy to load of 526,281,637 MWh, an annual peak load of 95,208 MW and a 12 Coincident Peak ("12 CP") load of 78,695 MW. Neglecting exports and wheel-throughs of power, and assuming little to no growth in energy sales and demand, an 100 MW (i.e., 100,000 kW demand), 80% load factor customer whose 12 CP demand is equal to its annual peak demand of 100 MW would be responsible for 0.1332% (700,800 MWh of 526,281,637 MWh) of total MISO MVP transmission investment cost under the MISO's proposed per MWh rate versus 0.1271% (100 MW of 78,695 MW) of total MISO MVP transmission investment cost if the transmission rate remained based on monthly coincident peak demand and Reserved Capacity. Thus, for this customer, the MISO's proposed per MWh rate would increase the customer's share of total MISO MVP transmission investment by nearly 5%.

28. Furthermore, if this customer's 12 CP demand was instead only equal to 5% more than its average hourly demand of 80 MW, the situation is even graver. In this latter situation, the customer's share of total MISO MVP transmission investment cost under a monthly coincident peak demand and Reserved Capacity based rate would fall from 0.1271% to 0.1067% (84 MW of 78,695 MW). Thus, in this latter case the MISO's per MWh rate proposal would assign nearly 25% more of the MISO's total MVP transmission investment cost to the customer than if the MISO continued to use a transmission rate based on monthly coincident peak demand and Reserved Capacity. Assuming $16 billion in total MVP transmission investment cost, this amounts to shifting approximately $4.2 million ($16 billion x (0.1332% - 0.1067%)) of that total investment cost to the one customer in question versus the portion of that investment that would have been allocated to that customer under a monthly coincident peak demand and Reserved Capacity based transmission rate.

29. A number of the manufacturing and mining companies participating in Industrial Customers have loads with a demand well in excess of 100 MW, a load factor well in excess of 80% or both. They would be even more severely affected by MISO's proposed move to a transmission rate based on total energy consumption than the hypothetical customer in my illustrative example.

30. As I have noted, the cost for transmission projects to (i) meet reliability requirements, (ii) provide economic benefits and (iii) allow for the interconnection and delivery of power from public policy-mandated renewable generation projects is not driven by total energy consumption.

31. The MISO has not met its burden to show that there is a compelling reason to move from transmission rates based on monthly coincident peak demand and Reserved Capacity to transmission rates based on total energy consumption.

32. MISO Staff witness Ms. Jennifer Curran indicates the MVP cost allocation proposal does not make an upfront allocation of costs based on any analysis of benefits and usage at a specific point in time, but instead allocates costs based on usage over time such that as entities that use and benefit from MVPs change over time, the MVP cost allocation method properly assigns the appropriate level of costs to those users (Curran Testimony. at 10).

33. I disagree with the implied contention that a total energy usage based transmission rate is more effective at allocating costs to reflect changes in beneficiaries than transmission rates based on monthly coincident peak demand and Reserved Capacity. In both cases, as the usage of the transmission system by customers changes, the total energy usage, monthly coincident peak demand and Reserved Capacity of those customers will likely all change. Point-to-Point transmission customers cannot escape Reserved Capacity charges. Furthermore, it is generally not practical for Network Transmission Service Customers to strategically target demand reductions to <u>only</u> the system peak hour of a month in order to avoid transmission service charges. Even if the latter was possible, it could be readily addressed by averaging customer demand values for several system peak hours of a given month together, similar to what is done by PJM when determining capacity resource responsibilities based on annual coincident peak demand. Finally, I would note that MISO has not demonstrated a nexus between the receipt of benefits from these projects and total energy usage.

34. MISO witness Jennifer Curran testifies that a usage (i.e., per MWh) charge is warranted under the MVP cost allocation proposal because energy flows and corresponding benefits from MVPs will occur in all hours of the year, not just during peak demand hours (Curran Testimony at 12).

35. I also disagree with this assertion. The benefits from these projects may occur in different hours of the year depending on whether the project is driven by reliability, economics or renewable generation mandates, but that does not mean that the benefit is even roughly spread over all hours of the year. Depending on the particular project in question, the benefit could be concentrated at the time of system peak demand, at the time of peak wind generation energy production in a particular area, during off-peak hours, during on-peak hours or during shoulder hours. Furthermore, as I have noted, economic projects often involve accelerations of projects that are needed for reliability. There has been no demonstration by MISO that transmission rates that are based on total energy usage are better at being roughly commensurate to the benefits enabled by the projects whose cost is being recovered through those rates than transmission rates based on monthly coincident peak demand, Reserved Capacity and the nameplate capacity of wind generation being accessed.

<u>**CONLCUSION**</u>

36. For the reasons I have discussed, I conclude that MISO's proposal to allocate the cost of its MVPs to load, exports and the wheeling of power across the MISO footprint is not just and reasonable because it is not consistent with cost causation, subsidizes centralized wind generation and is not roughly commensurate with the benefits that would be received from such projects. I also conclude that the proposed use of transmission rates based on total energy usage rather than transmission rates based on

monthly coincident peak demand, Reserved Capacity and the nameplate capacity of wind generation being accessed would on a going forward basis unduly and unnecessarily shift transmission investment costs from low load factor customers to high load factor customers. Finally, I conclude that MISO has not demonstrated that transmission rates based on total energy usage are any more effective at tracking changes in the beneficiaries of transmission projects than transmission rates based on monthly coincident peak demand, Reserved Capacity and the nameplate capacity of wind generation being accessed.

James R. Dauphinais

James R. Dauphinais

Subscribed and sworn to before me this 9th day of September, 2010.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2013
Commission # 09706793

Maria E. Decker

Notary Public

Qualifications of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation I was employed by the Transmission Planning Department of the Northeast Utilities Service Company as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow and power system stability computer simulations. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1997 I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

In addition to my technical responsibilities, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000, Montana Power Company, Docket No. ER98-2382-000, Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003, SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000, Alliance Companies, et al., Docket No. EL02-65-000, et al., Entergy Services, Inc., Docket No. ER01-2201-000, and Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000. I have also filed or presented testimony before the Colorado Public Utilities Commission, Connecticut Department of Public Utility Control, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Public Utility Commission of Texas, the Wisconsin Public Service Commission and various committees of the Missouri State Legislature. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, fuel adjustment clauses, generation interconnection, interruptible rates, market power, market structure, prudency, resource planning, standby rates, transmission losses, transmission planning and transmission rates.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several working groups of the Midwest Independent Transmission System Operator, Inc. ("MISO"), including the Congestion Management Working Group. I am currently an alternate member of the MISO Advisory Committee in the end-use customer sector on behalf of a group of industrial end-use customers in Illinois. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power Engineering Society of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.